Enable Midstream Partners, LP
Form 10-K
February 19, 2019
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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 10-K

þ 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
¨ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from _____to_____
Commission File No. 1-36413

ENABLE MIDSTREAM PARTNERS, LP
(Exact name of registrant as specified in its charter)

Delaware	72-1252419
(State or jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

One Leadership Square, 211 North Robinson Avenue, Suite 150
Oklahoma City, Oklahoma 73102
(Address of principal executive offices) (Zip Code)
Registrant's telephone number, including area code: (405) 525-7788

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

Title of each class	Name of each exchange on which registered
Common Units Representing Limited Partner Interests	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.
þ 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 þ 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. þ Yes ¨ 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). þ Yes ¨ No
Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§ 229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ¨

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	þ	Accelerated filer	¨
Non-accelerated filer	¨	Smaller reporting company	¨
		Emerging growth company	¨

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. ¨

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

The aggregate market value of the Common Units held by non-affiliates of the registrant, based upon the closing price of $17.11 per common unit on June 29, 2018, was approximately $1,510 million.

As of February 1, 2019, there were 433,247,600 common units outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

None

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GLOSSARY

2015 Term Loan Agreement.	$450 million unsecured term loan agreement dated July 31, 2015.
2019 Notes.	$500 million aggregate principal amount of the Partnership's 2.400% senior notes due 2019.
2019 Term Loan Agreement.	$1.0 billion unsecured term loan agreement dated January 29, 2019.
2024 Notes.	$600 million aggregate principal amount of the Partnership's 3.900% senior notes due 2024.
2027 Notes.	$700 million aggregate principal amount of the Partnership's 4.400% senior notes due 2027.
2028 Notes.	$800 million aggregate principal amount of the Partnership's 4.950% senior notes due 2028.
2044 Notes.	$550 million aggregate principal amount of the Partnership's 5.000% senior notes due 2044.
Adjusted EBITDA.	Please read "Measures We Use to Evaluate Results of Operations" under Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations" for the definition.
Adjusted interest expense.	Please read "Measures We Use to Evaluate Results of Operations" under Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations" for the definition.
ArcLight.	ArcLight Capital Partners, LLC, a Delaware limited liability company, its affiliated entities ArcLight Energy Partners Fund V, L.P., ArcLight Energy Partners Fund IV, L.P., Bronco Midstream Partners, L.P., Bronco Midstream Infrastructure LLC and Enogex Holdings LLC, and their respective general partners and subsidiaries.
ASC.	Accounting Standards Codification.
ASU.	Accounting Standards Update.
Atoka.	Atoka Midstream LLC, in which the Partnership owns a 50% interest as of December 31, 2018, which provides gathering and processing services to customers in the Arkoma Basin in Oklahoma.
ATM Program.	The offer and sale, from time to time, of common units representing limited partner interests having an aggregate offering price of up to $200 million in quantities, by sales methods and at prices determined by market conditions and other factors at the time of such sales, pursuant to that certain ATM Equity Offering Sales Agreement, entered into on May 12, 2017.
Barrel.	42 U.S. gallons of petroleum products.
Bbl.	Barrel.
Bbl/d.	Barrels per day.
Bcf.	Billion cubic feet.
Bcf/d.	Billion cubic feet per day.
Board of Directors.	The board of directors of Enable GP, LLC.
Btu.	British thermal unit. When used in terms of volume, Btu refers to the amount of natural gas required to raise the temperature of one pound of water by one degree Fahrenheit at one atmospheric pressure.
CAA.	Clean Air Act, as amended.
CEA.	Commodities Exchange Act.
CenterPoint Energy.	CenterPoint Energy, Inc., a Texas corporation, and its subsidiaries.
CERCLA.	Comprehensive Environmental Response, Compensation and Liability Act of 1980.
CFTC.	Commodity Futures Trading Commission.
Condensate.	A natural gas liquid with a low vapor pressure, mainly composed of propane, butane, pentane and heavier hydrocarbon fractions.
DCF.	Distributable Cash Flow. Please read "Measures We Use to Evaluate Results of Operations" under Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations" for the definition.

DHS.	Department of Homeland Security.
Distribution coverage ratio.	Please read “Measures We Use to Evaluate Results of Operations” under Item 7, “Management’s Discussion and Analysis of Financial Condition and Results of Operations” for the definition.
Dodd-Frank Act.	Dodd-Frank Wall Street Reform and Consumer Protection Act.
DOT.	Department of Transportation.

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DRIP.	Distribution Reinvestment Plan entered into on June 23, 2016, which offers owners of our common units the ability to purchase additional common units by reinvesting all or a portion of the cash distributions paid to them on their common units.
EGT.	Enable Gas Transmission, LLC, a wholly owned subsidiary of the Partnership 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 GP.	Enable GP, LLC, a Delaware limited liability company and the general partner of Enable Midstream Partners, LP.
Enable Midstream Services.	Enable Midstream Services, LLC, a wholly owned subsidiary of Enable Midstream Partners, LP.
EOCS.	Enable Oklahoma Crude Services, LLC, formerly Velocity Holdings, LLC, a wholly owned subsidiary of the Partnership that provides crude oil and condensate gathering services in the SCOOP and STACK plays of the Anadarko Basin in Oklahoma.
EOIT.	Enable Oklahoma Intrastate Transmission, LLC, formerly Enogex LLC, a wholly owned subsidiary of the Partnership that operates a 2,200-mile intrastate pipeline that provides natural gas transportation and storage services to customers in Oklahoma.
EOIT Senior Notes.	\$250 million aggregate principal amount of the EOIT's 6.25% senior notes due 2020.
EPA.	Environmental Protection Agency.
EPAct of 2005.	Energy Policy Act of 2005.
ERISA.	Employee Retirement Income Security Act of 1974.
Exchange Act.	Securities Exchange Act of 1934, as amended.
FASB.	Financial Accounting Standards Board.
FERC.	Federal Energy Regulatory Commission.
Fractionation.	The separation of the heterogeneous mixture of extracted NGLs into individual components for end-use sale.
GAAP.	Accounting principles generally accepted in the United States of America.
Gas imbalance.	The difference between the actual amounts of natural gas delivered from or received by a pipeline, as compared to the amounts scheduled to be delivered or received.
General partner.	Enable GP, LLC, a Delaware limited liability company and the general partner of Enable Midstream Partners, LP.
GHG.	Greenhouse gas.
Gross margin.	Please read "Measures We Use to Evaluate Results of Operations" under Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations" for the definition.
HLPSA.	Hazardous Liquid Pipeline Safety Act of 1979.
ICA.	Interstate Commerce Act.
ICE.	Intercontinental Exchange.
IPO.	Initial public offering of Enable Midstream Partners, LP.
IRS.	Internal Revenue Service.
LDC.	Local distribution company involved in the delivery of natural gas to consumers within a specific geographic area.
Lean gas.	Natural gas that is primarily methane.
LIBOR.	London Interbank Offered Rate.
LNG.	Liquefied natural gas.
MAOP.	Maximum allowable operating pressure for gas pipelines.
MBbl.	Thousand barrels.
MBbl/d.	Thousand barrels per day.

MMBtu.	Million British thermal units.
MMcf.	Million cubic feet of natural gas.
MMcf/d.	Million cubic feet per day.
MOP.	Maximum operating pressure for hazardous liquid pipelines.

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MRT.	Enable Mississippi River Transmission, LLC, a wholly owned subsidiary of the Partnership that operates a 1,600-mile interstate pipeline that provides natural gas transportation and storage services principally in Texas, Arkansas, Louisiana, Missouri and Illinois.
NEPA.	National Environmental Policy Act.
NGA.	Natural Gas Act of 1938.
NGLs.	Natural gas liquids, which are the hydrocarbon liquids contained within the natural gas stream including condensate.
NGPA.	Natural Gas Policy Act of 1978.
NGPSA.	Natural Gas Pipeline Safety Act of 1968.
NYMEX.	New York Mercantile Exchange.
NYSE.	New York Stock Exchange.
OCC.	Oklahoma Corporation Commission.
OGE Energy.	OGE Energy Corp., an Oklahoma corporation, and its subsidiaries.
OPA.	Oil Pollution Act of 1990.
OSHA.	Occupational Safety and Health Act of 1970.
Partnership.	Enable Midstream Partners, LP, a Delaware limited partnership, and its subsidiaries.
Partnership Agreement.	Fifth Amended and Restated Agreement of Limited Partnership of Enable Midstream Partners, LP dated as of November 14, 2017.
PHMSA.	Pipeline and Hazardous Materials Safety Administration.
Purchase Agreement.	Purchase Agreement, dated January 28, 2016, by and between the Partnership and CenterPoint Energy, Inc. for the sale by the Partnership and purchase by CenterPoint Energy, Inc. of Series A Preferred Units.
PVIR.	Preventable Vehicle Incident Rate.
RCRA.	Resource Conservation and Recovery Act of 1976.
Revolving Credit Facility	$1.75 billion senior unsecured revolving credit facility.
Rich gas.	Natural gas containing higher concentrations of NGLs.
SCOOP.	South Central Oklahoma Oil Province.
SDWA.	Safe Drinking Water Act.
SEC.	Securities and Exchange Commission.
Securities Act.	Securities Act of 1933, as amended.
Series A Preferred Units.	10% Series A Fixed-to-Floating Non-Cumulative Redeemable Perpetual Preferred Units representing limited partner interests in the Partnership.
SESH.	Southeast Supply Header, LLC, in which the Partnership owns a 50% 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.
Sponsors.	CenterPoint Energy and OGE Energy.
STACK.	Sooner Trend Anadarko Basin Canadian and Kingfisher Counties.
Superfund.	Comprehensive Environmental Response, Compensation and Liability Act of 1980.
TBtu.	Trillion British thermal units.
TBtu/d.	Trillion British thermal units per day.
Tcf.	Trillion cubic feet of natural gas.
TRIR.	Total Recordable Incident Rate.
VPP.	Velocity Pipeline Partners, LLC, a Delaware limited liability company, in which the Partnership, through EOCS, owns a 60% joint venture interest in a 26-mile pipeline system with a third party which owns and operates a refinery connected to the EOCS system as of December 31, 2018.
WTI.	West Texas Intermediate.
Wynnewood Refinery.	A refinery owned by CVR Refining, LP and connected to VPP.

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FORWARD-LOOKING STATEMENTS

Some of the information in this report may contain forward-looking statements. Forward-looking statements give our current expectations, contain projections of results of operations or of financial condition, or forecasts of future events. Words such as “could,” “will,” “should,” “may,” “assume,” “forecast,” “position,” “predict,” “strategy,” “expect,” “intend,” “p “anticipate,” “believe,” “project,” “budget,” “potential,” or “continue,” and similar expressions are used to identify forward-loo statements. Without limiting the generality of the foregoing, forward-looking statements contained in this report include our expectations of plans, strategies, objectives, growth and anticipated financial and operational performance, including revenue projections, capital expenditures and tax position. Forward-looking statements can be affected by assumptions used or by known or unknown risks or uncertainties. Consequently, no forward-looking statements can be guaranteed.

A forward-looking statement may include a statement of the assumptions or bases underlying the forward-looking statement. We believe that we have chosen these assumptions or bases in good faith and that they are reasonable. However, when considering these forward-looking statements, you should keep in mind the risk factors and other cautionary statements in this report. Those risk factors and other factors noted throughout this report could cause our actual results to differ materially from those disclosed in any forward-looking statement. You are cautioned not to place undue reliance on any forward-looking statements. You should also understand that it is not possible to predict or identify all such factors and should not consider the following list to be a complete statement of all potential risks and uncertainties. Factors that could cause our actual results to differ materially from the results contemplated by such forward-looking statements include:

- changes in general economic conditions;
- competitive conditions in our industry;
- actions taken by our customers and competitors;
- the supply and demand for natural gas, NGLs, crude oil and midstream services;
- our ability to successfully implement our business plan;
- our ability to complete internal growth projects on time and on budget;
- the price and availability of debt and equity financing;
- strategic decisions by CenterPoint Energy and OGE Energy regarding their ownership of us and Enable GP;
- operating hazards and other risks incidental to transporting, storing, gathering and processing natural gas, NGLs, crude oil and midstream products;
- natural disasters, weather-related delays, casualty losses and other matters beyond our control;
- interest rates;
- the timing and extent of changes in labor and material prices;
- labor relations;
- large customer defaults;
- changes in the availability and cost of capital;
- changes in tax status;
- the effects of existing and future laws and governmental regulations;
- changes in insurance markets impacting costs and the level and types of coverage available;
- the timing and extent of changes in commodity prices;
- the suspension, reduction or termination of our customers’ obligations under our commercial agreements;
- disruptions due to equipment interruption or failure at our facilities, or third-party facilities on which our business is dependent;
- the effects of current or future litigation; and
- other factors set forth in this report and our other filings with the SEC.

Forward-looking statements speak only as of the date on which they are made. We expressly disclaim any obligation to update or revise any forward-looking statement, whether as a result of new information, future events or otherwise, except as required by law.

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PART I

Item 1. Business

Overview

Enable Midstream Partners, LP is a Delaware limited partnership formed in May 2013 by CenterPoint Energy, OGE Energy and ArcLight to own, operate and develop midstream energy infrastructure assets strategically located to serve our customers. We completed our IPO in April 2014, and we are traded on the NYSE under the symbol “ENBL.” Our general partner is owned by CenterPoint Energy and OGE Energy. In this report, the terms “Partnership” and “Registrant” as well as the terms “our,” “we,” “us” and “its,” are sometimes used as abbreviated references to Enable Midstream Partners, LP together with its consolidated subsidiaries.

Our assets and operations are organized into two reportable segments: (i) gathering and processing and (ii) transportation and storage. Our gathering and processing segment primarily provides natural gas gathering and processing to our producer customers and crude oil, condensate and produced water gathering services to our producer and refiner customers. Our 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.

Our 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. Our crude oil gathering assets are located in Oklahoma and North Dakota and serve crude oil production in the Anadarko and Williston Basins. Our 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.

As of December 31, 2018, our portfolio of midstream energy infrastructure assets primarily included:
- approximately 13,900 miles of natural gas, crude oil, condensate and produced water gathering pipelines;
- 15 major processing plants with 2.6 Bcf/d of processing capacity;
- approximately 7,800 miles of interstate pipelines (including SESH);
- approximately 2,300 miles of intrastate pipelines; and
- eight natural gas storage facilities with 84.5 Bcf of storage capacity.

Our website address is www.enablemidstream.com. Documents and information on our website are not incorporated by reference in this report. Our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and amendments to those reports filed with or furnished to the SEC are available, free of charge, on our website as soon as reasonably practicable after we electronically file or furnish such materials.

Our Business Strategies

Our primary business objective is to increase the cash available for distribution to our unitholders over time while maintaining our financial flexibility. We strive to meet this objective through the following strategies:

- Capitalize on Organic Growth Opportunities Associated with Our Strategically Located Assets: We own and operate assets servicing four major producing basins in the United States, including some of the most productive shale plays in these basins. We intend to grow our business by utilizing a disciplined approach emphasizing capital efficiency when developing new midstream energy infrastructure projects to support new and existing customers in these areas.

- Maintain Strong Customer Relationships to Attract New Volumes and Expand Beyond Our Existing Asset Footprint and Business Lines: Management believes that we have built a strong and loyal customer base through exemplary customer service and reliable project execution. We have invested in organic growth projects in support of our existing and new customers. We work to maintain and build relationships with key producers and suppliers in an effort to attract new volumes and expansion opportunities.
- Continue to Minimize Direct Commodity Price Exposure Through Fee-Based Contracts: We continually seek ways to minimize our exposure to commodity price risk. Management believes that focusing on fee-based revenues reduces

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our direct commodity price exposure. We intend to maintain our focus on increasing the percentage of long-term, fee-based contracts with our customers.

- Grow Through Accretive Acquisitions: We continually evaluate potential acquisitions of complementary assets with the potential for attractive returns in new and existing operating areas and midstream business lines. We will continue to analyze acquisition opportunities using disciplined financial and operating practices, including evaluating and managing risks to cash available for distribution.

Our Sponsors

CenterPoint Energy and OGE Energy each own a significant interest in us. As of December 31, 2018, CenterPoint Energy owned 54.0% of our common units and 100% of our Series A Preferred Units, and OGE Energy owned 25.6% of our common units. In addition, our sponsors own Enable GP, our general partner. As of December 31, 2018, CenterPoint Energy owned a 50% management interest and a 40% economic interest in our general partner, and OGE Energy owned a 50% management interest and a 60% economic interest in our general partner. Enable GP owns the non-economic general partner interest in us and all of our incentive distribution rights.

CenterPoint Energy (NYSE: CNP) is a public utility holding company whose operating subsidiaries own and operate electric transmission and distribution facilities, own and operate natural gas distribution facilities, and supply natural gas to commercial, industrial and utility customers. In the first quarter of 2016, CenterPoint Energy announced that it was evaluating strategic alternatives for its investment in Enable. In the first quarter of 2018, CenterPoint Energy disclosed that it had decided not to pursue a sale or spin-off qualifying under Section 355 of the U.S. Internal Revenue Code at that time and that, while a transaction for all of its interests in the Partnership was not viable at that time, it may pursue such a transaction if it becomes viable in the future. CenterPoint Energy also disclosed that it may reduce its investment in the Partnership through a sale of all or a portion of the Partnership common units it owns in the public equity markets or otherwise, subject to certain limitations.

OGE Energy (NYSE: OGE) is an energy services provider offering physical delivery and related services for electricity.

Our sponsors are customers of our transportation and storage business. For the year ended December 31, 2018, approximately 1% of our gross margin was derived from transportation and storage contracts with an electric utility owned by OGE Energy. For the year ended December 31, 2018, approximately 7% of our total gross margin was derived from transportation and storage contracts servicing LDCs owned by CenterPoint Energy.

In addition, our sponsors have entered into a number of agreements affecting us. For a more detailed description of our relationship and agreements with CenterPoint Energy and OGE Energy, please read Item 13. “Certain Relationships and Related Transactions, and Director Independence.” Although management believes our relationships with CenterPoint Energy and OGE Energy are positive attributes, there can be no assurance that we will benefit from these relationships or that these relationships will continue.

Our Assets and Operations

Our assets and operations are organized into two reportable segments: (i) gathering and processing and (ii) transportation and storage.

We report natural gas gathered, processed and transported by energy content stated in millions or trillions of British thermal units (“MMBtu” or “TBtu”). We report natural gas processing, transportation, and storage capacity by volume stated in millions or billions of cubic feet (“MMcf” or “Bcf”), and we also report processing inlet volumes in millions of cubic feet. An MMcf of pipeline quality natural gas generally has an energy content of 1,000 MMbtu. We report crude oil, condensate and product water capacities, crude oil, condensate, and produced water gathered, NGLs production capacity, and NGLs produced and sold, by volume stated in barrels or thousands of barrels (“Bbl” or “Mbbl”).

Gathering and Processing

We own and operate substantial natural gas gathering and processing and crude oil, condensate and produced water gathering assets in five states. Our 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. We provide a variety of services to the active producers in

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our operating areas, including gathering, compressing, treating, and processing natural gas, fractionating NGLs, and gathering crude oil, condensate and produced water. We serve shale and other unconventional plays in the basins in which we operate.

Natural Gas

- Anadarko Basin (Oklahoma, Texas Panhandle). We have natural gas gathering and processing operations in those portions of the Anadarko Basin located in Oklahoma and the Texas Panhandle where, as of December 31, 2018, we served over 200 producers. Our operations include gathering and processing natural gas produced from the SCOOP, STACK, Granite Wash, Cleveland, Marmaton, Tonkawa, Cana Woodford and Mississippi Lime plays. The current focus of our Anadarko Basin gathering and processing operations is primarily on rich gas production.

- Arkoma Basin (Oklahoma, Arkansas). In the Arkoma Basin, our operations primarily serve the Woodford Shale play located in Oklahoma and the Fayetteville Shale play located in Arkansas. Our Arkoma Basin gathering and processing operations serve both rich and lean gas production. As of December 31, 2018, we served more than 80 producers in the Arkoma Basin.

- Ark-La-Tex Basin (Arkansas, Louisiana and Texas). We have gathering and processing operations in the Ark-La-Tex Basin located in Arkansas, Louisiana and Texas. Our Ark-La-Tex gathering and processing operations primarily serve the Haynesville, Cotton Valley and the lower Bossier plays. As of December 31, 2018, we served over 100 producers in the Ark-La-Tex Basin where our gathering and processing operations provide service for both rich and lean gas production.

Crude Oil, Condensate and Produced Water

- Anadarko Basin (Oklahoma). In the Anadarko Basin, we have operations that are located in Oklahoma. Our operations in the Anadarko Basin include the gathering of crude oil and condensate from producers in the SCOOP and STACK (including the area where the SCOOP and STACK come together known as the Merge play) plays. As of December 31, 2018, we served three producers and one refinery customer.

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- Williston Basin (North Dakota). In the Williston Basin, we have operations in the Bakken Shale that are located in North Dakota. The focus of our operations in the Williston Basin is the gathering of crude oil and produced water for XTO Energy Inc. (XTO), an affiliate of ExxonMobil Corporation, with pipeline gathering systems in Dunn, McKenzie, Williams and Mountrail Counties of North Dakota.

Natural Gas Gathering and Processing Assets. The following table sets forth certain information regarding our natural gas gathering and processing assets as of or for the year ended December 31, 2018:

Asset/Basin	Approximate Length (miles)	Approximate Compression (Horsepower)	Average Gathered Volume (TBtu/d)	Number of Processing Plants	Processing Capacity (MMcf/d)	NGLs Produced (MBbl/d) (1)
Anadarko Basin (2)	8,600	857,800	2.21	11	1,845	113.63
Arkoma Basin	3,000	142,900	0.55	1	60	6.55
Ark-La-Tex Basin (3)	1,800	160,200	1.72	3	645	9.80
Total	13,400	1,160,900	4.48	15	2,550	129.98

(1) Excludes condensate.

(2) Anadarko Basin processing capacity does not include firm contracted capacity of 400 MMcf/d at Energy Transfer’s Godley plant.

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

Our natural gas gathering systems consist of networks of pipelines that collect natural gas from points at or near our customers’ wells for delivery to plants for processing or pipelines for transportation. Natural gas is moved from the receipt points to the delivery points on our gathering systems by the use of compression.

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The following table sets forth information with respect to our natural gas processing plants as of or for the year ended December 31, 2018:

Processing Plant Assets [1]	Year Installed		Type of Plant	Average Daily Inlet Volumes (MMcf/d)	Inlet Capacity (MMcf/d)	NGL Production Capacity (Bbl/d)[2]
Anadarko						
Bradley II	2016		Cryogenic	164	200	28,000
Bradley	2015		Cryogenic	181	200	28,000
McClure	2013		Cryogenic	206	200	22,000
Wheeler	2012		Cryogenic	149	200	22,000
South Canadian	2011		Cryogenic	206	200	26,000
Clinton	2009		Cryogenic	112	120	14,000
Roger Mills	2008		Refrigeration	31	100	—
Canute	1996		Cryogenic	34	60	4,300
Cox City	1994		Cryogenic	154	180	14,500
Thomas	1981		Cryogenic	112	135	9,900
Calumet	1969		Lean Oil	150	250	8,000
Arkoma						
Wetumka	1983		Cryogenic	48	60	5,000
Ark-La-Tex						
Panola	2007		Cryogenic	71	100	8,000
Sligo [3]	2004		Refrigeration	39	225	1,400
Waskom	1995	[4]	Cryogenic	186	320	14,500
Total				1,843	2,550	205,600

(1) In addition to the processing plants listed above, the Partnership is a party to a 10-year gathering and processing agreement, which became effective on July 1, 2018, and provides for 400 MMcf/d of deliveries to Energy Transfer, LP’s Godley Plant in Johnson County, Texas.
(2) Excludes condensate.
(3) Average daily inlet volumes and inlet capacity includes 21 MMcf/d and 25 MMcf/d, respectively, related to a separate cryogenic unit.
(4) A processing plant has been in operation on the Waskom plant site since 1940. The Waskom plant was upgraded to cryogenic in 1995.

The natural gas processing assets in the Anadarko Basin include 11 processing plants, 10 of which are interconnected through our super-header system. The super-header system is configured to facilitate the flow of natural gas across our operating areas in western Oklahoma and the Texas Panhandle to the Bradley II, Bradley, McClure, Wheeler, South Canadian, Clinton, Canute, Cox City, Thomas and Calumet processing plants. The super-header system allows us to optimize the utilization of the connected processing plants and additional third party contracted capacity at Energy Transfer, LP’s Godley plant. Similarly, the natural gas processing assets in the Ark-La-Tex Basin include three processing plants, of which Waskom and Panola are interconnected to optimize the utilization of these processing plants.

Natural gas that is gathered, and when applicable, processed, is typically redelivered to our customers at interconnections with transportation pipelines. Our gathering lines interconnect with both our interstate and intrastate pipelines, as well as other interstate and intrastate pipelines, including the Acadian, ANR, ETC Tiger, Gulf South, NGPL, Northern Natural, Panhandle Eastern, Regency, Southern Natural Gas, Tennessee Gas, Oklahoma Gas

Transmission and Entergy Transfer Katy pipelines. These connections provide producers with access to a variety of natural gas markets.

Natural gas is comprised primarily of methane, but at the wellhead natural gas may contain varying amounts of NGLs which may be separated at our processing plants from the wellhead natural gas. We typically purchase the NGLs produced at our processing plants, and most of the NGLs are delivered into third-party pipelines and transported to Conway, Kansas, or Mont Belvieu, Texas, where the NGLs are exchanged for fractionated NGLs that are sold under contract or on the spot market. At our Cox City, Calumet and Wetumka plants, we operate depropanizers that allow us to extract propane from the NGL stream and sell propane to local markets. Additionally, we operate a fractionator at our Waskom plant and sell ethane, propane, butane and natural gasoline to local markets.

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Crude Oil, Condensate and Produced Water Gathering Assets. The following table sets forth certain information regarding our crude oil gathering assets as of or for the year ended December 31, 2018:

Asset/Basin	Approximate Length (miles)	Design Capacity (MBbls/d)	Average Throughput Volume (MBbls/d)
Anadarko Basin crude oil and condensate (including VPP)	150	225	12.14
Williston Basin crude oil	175	58	28.93
Williston Basin produced water	150	19	12.18
Total	475	77	53.25

Our Anadarko Basin crude oil and condensate gathering assets are located in Oklahoma. These systems were designed and built to serve the crude oil and condensate production in the SCOOP and STACK plays (including the area where the SCOOP and STACK come together known as the Merge play). On our systems, crude oil and condensate is either received on gathering lines near our customers' wells or via truck unloading terminals. We do not take title to crude oil or condensate gathered on our systems. Crude oil and condensate gathered on our Anadarko Basin gathering systems can be redelivered to our customers through interconnections to the Basin Pipeline, the Red River Pipeline and the CVR Refining, LP refinery located at Wynnewood, Oklahoma (the Wynnewood Refinery).

Our Williston Basin crude oil and produced water gathering assets are located in the Bakken Shale in North Dakota. These systems were designed and built to serve the crude oil production of XTO in these areas. On our systems, crude oil is received on crude oil gathering pipelines near our customer's wells for delivery to third party transportation pipelines, and produced water is received by produced water gathering pipelines for delivery to third party disposal wells. We do not take title to crude oil or produced water gathered on our systems and we do not own or operate produced water disposal wells. Crude oil gathered on our Williston Basin gathering systems in Dunn and McKenzie Counties can be redelivered to our customers through interconnections to the BakkenLink Pipeline and the Dakota Access Pipeline. Crude oil gathered on our Williston Basin gathering systems in Williams and Mountrail Counties can be redelivered to our customer through interconnections to the Enbridge North Dakota Pipeline and the Dakota Access Pipeline.

Natural Gas Gathering and Processing Customers. For the year ended December 31, 2018, our top natural gas gathering and processing customers by gathered volumes were Continental Resources, Inc. (Continental), Vine Oil and Gas (Vine), GeoSouthern Energy Corporation (GeoSouthern), XTO, Tapstone Energy LLC (Tapstone), Apache Corporation (Apache), BP America Production Company (BP), QEP Resources, Inc. (QEP), FourPoint Energy, LLC (FourPoint) and Marathon Oil Corporation (Marathon Oil). For the year ended December 31, 2018, our top ten natural gas producer customers accounted for approximately 70% of our natural gas gathered volumes.

Crude Oil, Condensate and Produced Water Gathering Customers. Our Anadarko Basin crude oil gathering systems gathers crude oil and condensate from producers, which are primarily delivered to CVR Refining, LP. Our Anadarko Basin crude oil and condensate gathering system is an intrastate pipeline system, and the rates and terms of service are regulated by the Oklahoma Corporation Commission (OCC). Our Williston Basin crude oil and produced water gathering systems serve XTO. Crude oil on the Williston Basin systems is delivered for transportation on third party interstate pipeline systems, and produced water is delivered to third party injection wells. Our Williston Basin crude oil gathering systems, but not our produced water gathering systems, are considered interstate pipeline systems, and the rates and terms of service are regulated by FERC under the Interstate Commerce Act.

Contracts. Our 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.

- Under a typical fee-based processing arrangement, we process the raw natural gas to extract the NGLs, purchase the NGLs from the producer less a fee, return the processed natural gas to the producer and sell the NGLs for our own account.
- Under a typical percent-of-liquids processing arrangement, we process the raw natural gas to extract the NGLs, purchase the NGLs from the producer at a discount, return the processed natural gas to the producer and sell the NGLs for our own account.

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- Under a typical percent-of-proceeds processing arrangement, we process the raw natural gas to extract the NGLs, purchase the NGLs and an agreed upon percentage of the processed natural gas from the producer at a discount, return the remaining processed natural gas to the producer and sell the purchased natural gas and NGLs for our own account.
- Under a typical keep-whole arrangement, we process raw natural gas to extract the NGLs, return a quantity of the processed natural gas to the producer that is equivalent to the raw natural gas on a Btu basis and retain and sell the NGLs for our own account.

For the year ended December 31, 2018, 67%, 27% and 6% of our natural gas processing inlet volumes were processed under arrangements that were fee-based, percent-of-proceeds or percent-of-liquids, and keep-whole, respectively. For the year ended December 31, 2018, 72% of our gathering and processing gross margin was fee-based, and the remaining 28% of our gathering and processing gross margin was primarily from sales of commodities, including natural gas, natural gas liquids and condensate received under percent-of-proceeds, percent-of-liquids and keep-whole arrangements.

In lean gas areas, such as the eastern Arkoma Basin and the Haynesville Shale of the Ark-La-Tex Basin, some of our natural gas gathering contracts contain minimum volume commitments from our customers. Additionally, a portion of the crude oil gathered by our crude oil gathering system in the Williston Basin is under a contract with a minimum volume commitment. Under a minimum volume commitment, a customer agrees to either deliver a minimum volume of natural gas or crude oil to our system for service or pay the service fees for the minimum volume of natural gas or crude oil regardless of whether or not the minimum volume of natural gas or crude oil is delivered. We call any payment for the difference between the volume gathered and the minimum volume committed a shortfall payment. Some 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 shortfall payment. As of December 31, 2018, the percentage of our gathering and processing gross margin attributable to natural gas and crude oil gathering contracts with minimum volume commitments, and the volume commitment-weighted average remaining terms of those contracts, were as follows:

	Anadarko Basin	Arkoma Basin	Ark-La-Tex Basin	Williston Basin (2)	Total
Percentage of gathering and processing gross margin attributable to gathering contracts with minimum volume commitments	2 %	5 %	15 %	1 %	22 %
Percentage attributable to shortfall payments (1)	— %	81 %	12 %	— %	27 %
Natural gas volume commitment-weighted average remaining contract term (in years)	8.5	5.2	1.1	—	3.4
Crude oil and condensate volume commitment-weighted average remaining contract term (in years)	—	—	—	10.2	10.2

(1) Represents the percentage of gathering and processing gross margin from gathering contracts with minimum volume commitments that were attributable to shortfall payments.

(2) Under the Williston Basin contracts, if the customer ships in excess of the minimum volume, this volume commitment could end before the expiration of the contract term.

For our gathering and processing contracts that do not have minimum volume commitments, we strive to obtain acreage dedications. Under an acreage dedication, a customer agrees to deliver all of the natural gas, crude oil or condensate produced from a given area to our system for gathering, and, if applicable, processing. As of December 31, 2018, the gross acres dedicated under gathering agreements and the volume-weighted average remaining term for all gathering and processing contracts were as follows:

	Anadarko Basin	Arkoma Basin	Ark-La-Tex Basin	Williston Basin	Total
Gross acreage dedication (in millions)	5.4	1.2	1.2	0.3	8.1

Natural gas volume-weighted average remaining contract term (in years)	6.9	1.8	4.9	—	5.5
Crude oil and condensate volume-weighted average remaining contract term (in years)	13.9	—	—	10.7	12.6

Construction. Our gathering and processing business involves the construction of gathering and processing assets as needed to serve our existing and new customers. For example, during the year ended December 31, 2018, we constructed 400 miles of gathering pipelines, added 109,200 horsepower of compression and invested $487 million in the construction of gathering and processing assets. This construction included the completion of a rich natural gas pipeline that is capable of delivering approximately

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400 MMcf/d of rich natural gas from the Anadarko Basin to an interconnection with a third-party pipeline that in turn delivers rich natural gas to north Texas, providing a new market outlet for growing Anadarko Basin production. In conjunction with the construction of the rich natural gas pipeline, we 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. Even with the contracted 400 MMcf/d of processing capacity, the Partnership anticipates that there will be a need to resume construction of the previously announced Wildhorse Plant, a cryogenic processing facility we plan to connect to our super-header system in Garvin County Oklahoma, though likely not before 2020.

Competition. Competition for our 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. Our 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, we compete against other natural gas processors extracting and selling NGLs. Our primary competitors are other midstream companies who are active in the regions where we operate.

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

Acquisitions. In the fourth quarter of 2018, we acquired Velocity Holdings, LLC, a midstream company with a crude oil and condensate gathering system in the SCOOP and STACK plays of the Anadarko Basin, and renamed it Enable Oklahoma Crude Services, LLC (EOCS). The acquisition included approximately 150 miles of crude oil and condensate gathering pipelines capable of flowing approximately 225,000 Bbl/d across Grady, Stevens, Garvin and McClain counties in Oklahoma. A portion of EOCS's operations are conducted through a joint venture with a subsidiary of CVR Refining, LP in which EOCS owns 60% of the joint venture and operates its assets. Crude oil and condensate gathered on the system can be redelivered to our customers through interconnections to the Basin Pipeline, the Red River Pipeline and the Wynnewood Refinery. For the year ended December 31, 2018, 78% of crude oil and condensate gathered on the system was delivered to the Wynnewood Refinery.

Transportation and Storage

We own and operate interstate and intrastate natural gas transportation and storage systems across nine states. Our transportation and storage systems consist primarily of our interstate systems, EGT and MRT, our intrastate system, EOIT, and our investment in SESH. Our 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. Our transportation and storage assets also provide facilities where natural gas can be stored by customers.

The following table sets forth certain information regarding our transportation and storage assets as of or for the year ended December 31, 2018:

Transportation and Storage

Asset	Length (miles)	Compression (Horsepower)	Average Throughput (TBtu/d)	Transportation Capacity (Bcf/d) (1)	Transportation Firm Contracted Capacity (Bcf/d) (2)	Storage Capacity (Bcf)	Storage Firm Contracted Capacity (Bcf/d)
EGT	5,900	391,300	2.65	6.0	4.30	29.0	23.38
MRT	1,600	119,700	0.83	1.7	1.64	31.5	28.14

EOIT	2,300	218,800	2.08 [3]	— [3]	—	24.0	11.00
Subtotal	9,800	729,800	5.56	7.7	5.94	84.5	62.52
SESH	290	107,800	— [5]	— [4]	— [5]	— [5]	— [5]
Total	10,090	837,600	5.56	7.7	5.94	84.5	62.52

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

(2) Transportation Firm Contracted Capacity includes contracts with affiliates and our subsidiaries.

(3) Our EOIT pipeline system is a web-like configuration with multidirectional flow capabilities between numerous receipt and delivery points, which limits our ability to determine an overall system capacity. During the year ended December 31, 2018, the peak daily throughput was 2.6 TBtu/d or, on a volumetric basis, 2.6 Bcf/d.

(4) SESH has 1.09 Bcf/d of transportation capacity from Perryville, Louisiana to its endpoint in Mobile County, Alabama.

(5) We own a 50% interest in SESH and as such, do not include certain information regarding its transportation and storage assets in the table set forth above.

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Our transportation and storage assets were designed and built to primarily serve large natural gas and electric utilities in our areas of operation. In addition, our transportation and storage assets serve natural gas producers, industrial end users and natural gas marketers. For the year ended December 31, 2018, our top transportation and storage customers by revenue were affiliates of CenterPoint Energy, Spire Inc. (Spire), Continental, American Electric Power Co. (AEP), OGE Energy, Chesapeake Energy Corp., LS Power, Midcontinent Express Pipeline LLC (MEP), Entergy Corporation (Entergy) and Black Hills Corporation.

From time to time, our transportation and storage business involves the construction of natural gas pipelines as needed to serve our existing and new customers. For example, during the year ended December 31, 2018, we added 8,700 horsepower of compression and invested $126 million in the construction of transportation pipelines, including the Cana and STACK Expansion (CaSE) project, a system expansion providing firm transportation service for growing Anadarko Basin production, and an approximately 80-mile pipeline expanding the EOIT system to provide service to the OGE Energy Muskogee, Oklahoma power plant. In addition, in September 2018, we announced the development of the Gulf Run Pipeline, an interstate natural gas transportation project. The Gulf Run Pipeline project is designed to connect U.S. natural gas supplies to the liquefied natural gas (LNG) export market on the Gulf Coast.

Our transportation assets include approximately 10,090 miles of transportation pipelines in Texas, Oklahoma, Arkansas, Louisiana, Kansas, Mississippi, Alabama, Missouri and Illinois (including SESH), providing access to natural gas supplies from the Anadarko, Arkoma and Ark-La-Tex Basins to natural gas consuming markets in the Southeastern, Northeastern and Midwestern United States. Our storage assets, as of December 31, 2018, provide a combined capacity of 84.5 Bcf with 2.0 Bcf/d of aggregate maximum withdrawal capacity from our seven storage facilities in Oklahoma, Louisiana and Illinois and from our undivided 1/12th interest in the Bistineau Storage Facility in Louisiana. Boardwalk Pipeline Partners, LP owns an undivided 11/12th interest in, and operates, the Bistineau Storage Facility.

Our transportation and storage assets are comprised of three categories: (1) interstate transportation and storage, (2) intrastate transportation and storage and (3) our investment in SESH.

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Interstate Transportation and Storage

Our interstate transportation and storage business consists of EGT and MRT. As interstate pipelines, EGT and MRT are subject to regulation as natural gas companies by FERC under the NGA.

EGT

EGT provides natural gas transportation and storage services primarily to customers in Oklahoma, Texas, Arkansas, Louisiana, Missouri and Kansas. In addition to 5,900 miles of interstate pipelines with capacity of 6.0 Bcf/d, EGT has two underground natural gas storage facilities in Oklahoma and one underground natural gas storage facility in Louisiana, which, as of December 31, 2018, operate at a combined capacity of 29.0 Bcf with 739 MMcf/d of aggregate maximum withdrawal capacity.

Interconnections and Delivery Points. In addition to delivering natural gas to utilities and industrial end users in Oklahoma, Louisiana, Texas and Arkansas, EGT receives natural gas from and delivers natural gas to a variety of intrastate and interstate pipelines through its numerous interconnections. Those interconnections include SESH, ANR, Columbia Gulf, EOIT, Gulf South, MEP, MRT, SONAT, Tennessee Gas, Texas Eastern, Texas Gas and Trunkline. Through EGT’s interconnection with SESH, our customers have access to the Southeast power generation market. Through our interconnections with other pipelines, our customers have access to the Midwest and Northeast markets. Many of EGT’s interconnections are at our Perryville Hub, which provides the ability to move natural gas between 11 major interstate pipelines. As a result, EGT provides our customers with access to not only natural gas consuming markets in Oklahoma, Louisiana, Texas and Arkansas, but also most of the major natural gas consuming markets east of the Mississippi River. In addition, EGT provides our customers supplying those markets with access to natural gas from producing basins and shale plays across the Mid-continent, including the Anadarko, Arkoma and Ark-La-Tex Basins and the Barnett, Fayetteville, Granite Wash, Haynesville, SCOOP and STACK plays.

Customers. EGT primarily serves LDCs owned by CenterPoint Energy, producers in key plays in the Mid-continent, power plants, other LDCs and industrial end-users. EGT’s customers are primarily located in Arkansas, Louisiana, Oklahoma and Texas. For the year ended December 31, 2018, approximately 28% of EGT’s service revenue was attributable to contracts with LDCs

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owned by CenterPoint Energy with a volume-weighted average contract life of 2.3 years for transportation contracts and 2.3 years for storage contracts. In addition to CenterPoint Energy's LDCs, EGT's other major customers include Continental and AEP.

Contracts. Although EGT has established maximum rates for interstate transportation and storage services as required by FERC, EGT is authorized to enter into negotiated rate and discounted rate agreements with its customers. EGT's services are typically provided under firm, fee-based transportation and storage agreements. For the year ended December 31, 2018, approximately 54% of our transportation and storage gross margin was derived from EGT's firm contracts, 72% of EGT's transportation capacity was under firm contracts with a volume-weighted average remaining contract life of 3.0 years, and 81% of EGT's storage capacity was under firm contracts with a volume-weighted average remaining contract life of 2.3 years. All of EGT's firm transportation and storage contracts for CenterPoint Energy'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 Energy's LDCs in Arkansas, Louisiana, Oklahoma and Northeast Texas will be extended beyond March 31, 2021, pursuant to the terms of the approved contracts.

Seasonality. Customer demand for natural gas from EGT is usually greater during the winter, primarily due to LDC demand to serve residential and commercial natural gas requirements. In addition, EGT experiences seasonal impacts associated with storage spreads and basis spreads on interconnected pipelines, as well as power plant demand.

Competition. EGT competes with a variety of other interstate and intrastate pipelines across Texas, Oklahoma, Arkansas and Louisiana. Our management views the principal elements of competition among pipelines as rates, terms of service, flexibility and reliability of service. EGT provides both flexibility and reliability of service with access to multiple sources of supply in the Anadarko, Arkoma and Ark-La-Tex Basins and access to multiple markets in the Midwest, Northeast and Southeast through interconnections with other pipelines.

MRT

MRT provides natural gas transportation and storage services principally in Texas, Arkansas, Louisiana, Missouri and Illinois. In addition to 1,600 miles of interstate pipelines with capacity of 1.7 Bcf/d, MRT has one underground natural gas storage facility in Louisiana, which includes the East Unionville and West Unionville fields, and one underground natural gas storage facility in Illinois, which, as of December 31, 2018, operate at a combined capacity of 31.5 Bcf with 590 MMcf/d of aggregate maximum withdrawal capacity.

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Interconnections and Delivery Points. MRT receives natural gas from a variety of interstate and intrastate pipelines through its interconnections and delivers natural gas primarily to the St. Louis market. Those interconnections include EGT, Gulf South, NGPL, Ozark Gas Transmission, Texas Eastern, Texas Gas and Trunkline. From MRT’s west line, we provide our customers with access to supply from East Texas and North Louisiana, including the Haynesville Shale. From MRT’s mainline, we provide our customers with access to supply from the Anadarko, Arkoma and Ark-La-Tex Basins. Supply from the Fayetteville Shale is transported though our interconnection with EGT, Texas Gas and Ozark Gas Transmission. From MRT’s east line, we provide our customers with access to supply from the Mid-continent and the Marcellus Shale through our interconnections with NGPL and Trunkline. As a result, MRT provides the St. Louis market with access to natural gas from a variety of major producing basins across the U.S.

Customers. MRT primarily serves the St. Louis LDC owned by Spire. For the year ended December 31, 2018, 70% of MRT’s service revenue was attributable to Spire under contracts with a volume-weighted average contract life of 1.0 year for transportation contracts and 1.1 years for storage contracts. MRT’s other customers include utilities and industrial end users. MRT’s customers are primarily located in Arkansas, Missouri and Illinois.

Contracts. MRT’s services are typically provided under firm, fee-based transportation and storage agreements, with rates and terms of service regulated by FERC. For the year ended December 31, 2018, approximately 13% of our transportation and storage gross margin was derived from MRT’s firm contracts, 89% of MRT’s transportation capacity was under firm contracts with a volume-weighted average remaining contract life of 1.5 years and 96% of MRT’s storage capacity was under firm contracts with a volume-weighted average remaining contract life of 1.2 years. MRT’s firm transportation contracts representing 63% of Spire’s firm transportation capacity are scheduled to expire in July 2019 and 37% of Spire’s firm transportation capacity are scheduled to expire in July 2020. 32% of Spire’s firm storage contracts are scheduled to expire in May 2019 and 68% of Spire’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’s affiliates in the St. Louis market. Spire has indicated that it is targeting a 2019 in-service date for this pipeline. When the pipeline is placed in-service, we anticipate that Spire’s LDC’s need for firm transportation and storage capacity on MRT will decrease.

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Seasonality. Customer demand for natural gas on MRT is usually greater during the winter, primarily due to LDC demand to serve residential and commercial natural gas requirements. In addition, MRT experiences seasonal impacts associated with storage spreads and basis spreads on market-based pipelines.

Competition. MRT competes with various intrastate pipelines providing natural gas to the St. Louis market. In addition, Spire’s LDC is expected to switch an undetermined amount of demand to its affiliate, the interstate Spire STL Pipeline, when constructed. Our management views the principal elements of competition among pipelines as rates, terms of service, flexibility and reliability of service. MRT, through its interconnections with a variety of interstate and intrastate pipelines and its access to supply from a variety of producing basins, provides our customers with access to a variety of natural gas supply sources.

Intrastate Transportation and Storage

Our intrastate natural gas transportation and storage assets consist primarily of EOIT. EOIT provides transportation and storage services in Oklahoma. Our EOIT system delivers natural gas from the Anadarko and Arkoma Basins, including the SCOOP, STACK, Cana Woodford, Granite Wash, Cleveland, Tonkawa, and Mississippi Lime Shale plays in western Oklahoma and the Texas Panhandle, to utilities and industrial end users connected to EOIT and to interstate and intrastate pipelines interconnected with EOIT. EOIT had 2.08 TBtu/d of average daily throughput for the year ended December 31, 2018. In addition to 2,300 miles of intrastate pipelines, EOIT has two underground natural gas storage facilities in Oklahoma, which, as of December 31, 2018 operate at a combined capacity of 24 Bcf with 605 MMcf/d of aggregate maximum withdrawal capacity.

Interconnections and Delivery Points. EOIT has 79 interconnections, which include interconnects with EGT and 12 third-party interstate and intrastate natural gas pipelines, including ANR Pipeline, El Paso Natural Gas Pipeline, Gulf Crossing Pipeline Company LLC, MEP, Natural Gas Pipeline Company of America, Northern Natural Gas Company, ONEOK Gas Transmission, Ozark Gas Transmission, L.L.C., Panhandle Eastern Pipe Line, Postrock KPC Pipeline, LLC, Southern Star Central Gas Pipeline

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and ONEOK Western Trails Pipeline, L.L.C. In addition, EOIT connects to 44 end-user customers, including 14 natural gas-fired electric generation facilities in Oklahoma.

Customers. EOIT’s customers include Oklahoma’s two largest electric utilities, OG&E, an affiliate of OGE Energy and Public Service Company of Oklahoma (PSO), an affiliate of AEP. For the year ended December 31, 2018, approximately 7% of our total transportation and storage gross margin was attributable to firm contracts with OG&E, and approximately 3% of our transportation and storage gross margin was attributable to a firm contract with PSO. Our no-notice load-following transportation agreement with OG&E for three of its generating facilities was scheduled to terminate on April 1, 2019 and has been recontracted to extend through May 1, 2024 and will remain in effect year to year thereafter unless either party provides notice of termination to the other party at least 180 days prior to the commencement of the succeeding annual period. Our firm transportation agreement with OG&E, for one of its generating facilities began on December 1, 2018 and extends through December 1, 2038. Our transportation agreement with PSO extends through December 31, 2020 and includes the option for a one-year extension. EOIT’s customers also include other electric generators, LDCs, Arkoma and Anadarko Basin producers and industrial end users.

Contracts. EOIT provides fee-based firm and interruptible transportation and storage services on both an intrastate basis and, pursuant to Section 311 of the NGPA, on an interstate basis. For the year ended December 31, 2018, approximately 21% of our transportation and storage gross margin was derived from EOIT’s firm contracts. EOIT’s transportation capacity was under firm contracts with a volume-weighted average remaining contract life of 6.0 years and EOIT’s storage capacity was under firm contracts with a volume-weighted average remaining contract life of 1.0 years.

Seasonality. EOIT provides gas transmission delivery services to the majority of OG&E’s and all of PSO’s natural gas-fired electric generation facilities in Oklahoma. 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.

Competition. EOIT competes with a variety of interstate and intrastate pipelines in providing transportation and storage services in Oklahoma, including competing against several pipelines with which EOIT interconnects. We view competition in the transportation and storage market as primarily a function of rates, terms of services, flexibility and reliability of service. EOIT’s integrated transportation and storage system allows us to provide load following service to natural gas-fired power plants to allow the power plants the ability to regulate generation and meet the instantaneous changes in customer demand for electricity.

Our Investment in SESH

SESH is an approximately 290-mile interstate pipeline that provides transportation services in Louisiana, Mississippi and Alabama. We own a 50% interest in SESH and provide field operations for the pipeline. Enbridge Inc. owns the remaining 50% interest in SESH and provides gas control and commercial operations for the pipeline. As of December 31, 2018, SESH had 1.09 Bcf/d of transportation capacity from Perryville, Louisiana to its endpoint in Mobile County, Alabama.

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Interconnections and Delivery Points. SESH runs from the Perryville Hub in northeastern Louisiana to southwestern Alabama near the Gulf Coast. SESH has 20 interconnects with third-party natural gas pipelines and provides access to major Southeast and Northeast markets. Natural gas transported by SESH is primarily transported by the interconnecting pipelines to companies generating electricity for the Florida power market. SESH also interconnects with three high-deliverability storage facilities, Mississippi Hub Storage, Petal Gas Storage and Southern Pines Energy Center.

Customers and Contracts. SESH's customers are primarily companies that generate electricity for the Florida power market. The rates charged by SESH for interstate transportation services are regulated by FERC. SESH's transportation services are typically provided under firm, fee-based negotiated rate agreements. SESH's transportation contracts have a volume-weighted average remaining contract life of 3.8 years.

Seasonality. SESH is generally not impacted by seasonality. SESH's load factor generally remains constant throughout the year.

Competition. SESH competes with other interstate and intrastate pipelines providing access to the Southeast power generation market. Our management views the principal elements of competition among pipelines as rates and terms, flexibility and reliability of service.

Rate and Other Regulation

Federal, state and local regulation of pipeline gathering and transportation services may affect certain aspects of our business and the market for our products and services.

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Interstate Natural Gas Pipeline Regulation

EGT, MRT and SESH are subject to regulation by FERC and are considered "natural gas companies" under the Natural Gas Act (NGA). The NGA prohibits natural gas companies from granting any undue preference or advantage, or unduly discriminating against any person with respect to pipeline rates or terms and conditions of service, including unduly discriminatory or preferential access to information. FERC authority over natural gas companies that provide natural gas pipeline transportation services in interstate commerce includes:

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

Under the NGA, the rates for service on interstate facilities must be just and reasonable and not unduly discriminatory. Generally, the maximum recourse rates for interstate pipelines are based on the pipeline's cost of service including recovery of and a return on the pipeline's actual prudent investment cost. Key determinants in the ratemaking process are the total costs of providing service, allowed rate of return and throughput projections. Our interstate pipeline operations may be affected by changes in the demand for natural gas, the available supply and relative price of natural gas in the Mid-continent and Gulf Coast natural gas supply regions and general economic conditions.

Rate and tariff changes can only be implemented upon approval by FERC. Two primary methods are available for changing the rates, terms and conditions of service of an interstate natural gas pipeline. Under the first method, the pipeline voluntarily seeks a rate or tariff change by making a filing with FERC justifying the proposed change. FERC provides notice of the proposed change to the public through publication on its website and in the Federal Register. If FERC determines that a proposed change is just and reasonable, FERC grants approval of and allows the pipeline to implement the change. If FERC determines that a proposed change may not be just and reasonable, FERC may suspend the proposed change for up to five months. Subsequent to any suspension period ordered by FERC, the proposed change may be placed into effect by the company, pending final FERC approval. In most cases, a proposed rate change is placed into effect before a final FERC determination on such rate change, and the pipeline is permitted to collect the proposed rate subject to refund (plus interest). Under the second method, FERC may, on its own motion or based on a complaint filed by a third party, initiate a proceeding seeking to compel the company to change its rates, terms and/or conditions of service. If FERC determines that the existing rates, terms and/or conditions of service are unjust, unreasonable, unduly discriminatory or preferential, then any rate reduction or change that it orders generally will be effective prospectively from the date of the FERC order requiring this change.

Effective December 22, 2017, the Tax Cuts and Jobs Act of 2017 (Tax Cuts and Jobs Act) changed several provisions of the federal tax code, including a reduction in the maximum corporate tax rate. On March 15, 2018, in a set of related issuances, FERC addressed treatment of federal income tax allowances in regulated entity rates. FERC issued a Revised Policy Statement on Treatment of Income Taxes stating that it will no longer permit pipelines organized as master limited partnerships to recover an income tax allowance in their cost-of-service rates. FERC issued the Revised Policy Statement in response to a remand from the U.S. Court of Appeals for the D.C. Circuit in United Airlines v. FERC, in which the court determined that FERC had not justified its conclusion that a pipeline organized as a master limited partnership would not "double recover" its taxes under the current policy by both including an income-tax allowance in its cost-of-service and earning a return on equity calculated using the discounted cash flow methodology. On July 18, 2018, FERC issued an order denying requests for rehearing of its Revised Policy Statement because it is a non-binding policy and parties will have the opportunity to address the policy as applied in future cases. In the rehearing order, FERC clarified that a pipeline organized as 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. FERC also provided guidance that when a master limited partnership pipeline’s income tax allowance is eliminated from cost of service, previously accumulated deferred income taxes (ADIT) may also be eliminated as ADIT is not a true-up or tracker of money owed shippers.

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FERC also issued a Notice of Inquiry (NOI) requesting comments on the effect of the Tax Cuts and Jobs Act on FERC-jurisdictional rates. The NOI states that of particular interest to FERC is whether, and if so how, FERC should address changes relating to ADIT and bonus depreciation. Comments in response to the NOI were due on or before May 21, 2018. Actions FERC will take, if any, following receipt of responses to the NOI and any potential impacts from final rules or policy statements issued following the NOI on the rates the Partnership can charge for transportation services are unknown at this time, but could impact rates the Partnership is permitted to charge its customers.

Included in the issuances on March 15, 2018, is a Notice of Proposed Rulemaking (NOPR) proposing rules for implementation of the Revised Policy Statement and the corporate income tax rate reduction with respect to natural gas pipeline rates. On July 18, 2018, FERC issued a Final Rule adopting procedures that are generally the same as proposed in the NOPR with a few clarifications and modifications. With limited exceptions, the Final Rule requires 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. The Final Rule states that this information will allow FERC and other stakeholders to evaluate the impacts of the Tax Cuts and Jobs Act and the Revised Policy Statement on each individual pipeline’s rates. The Final Rule also requires that each FERC-regulated natural gas pipeline select one of four options: (i) file a limited NGA Section 4 filing reducing its rates only as required in relation to the Tax Cuts and Jobs Act and the Revised Policy Statement, (ii) commit to filing a general NGA Section 4 rate case in the near future, (iii) file a statement explaining why an adjustment to rates is not needed, or (iv) take no other action. For the limited NGA Section 4 option, FERC clarified that, notwithstanding the Revised Policy Statement, a pipeline organized as a master limited partnership does not need to eliminate its income tax allowance but, instead, can reduce its rates to reflect the reduction in the maximum corporate tax rate. At this time, we cannot predict the outcome of the Final Rule, but FERC’s adoption of the regulation could impact the rates the Partnership’s FERC-regulated entities are permitted to charge their customers. EGT filed its Form No. 501-G on October 11, 2018. On November 8, 2018, SESH filed its Form No. 501-G and a limited Section 4 rate reduction filing. As MRT had already filed a rate proceeding under NGA 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.

Even without action on the NOI or as contemplated in the Final Rule, the FERC or our shippers may challenge the cost of service rates we charge. FERC’s establishment of a just and reasonable rate is based on many components, and tax-related changes will affect tax-related accounts, such as the annual allowance for income taxes and the balance sheet amounts for accumulated deferred income taxes and related regulatory assets and liabilities, while other pipeline costs also will continue to affect FERC’s determination of just and reasonable cost-of-service rates. Although changes in these tax-related accounts may vary, other components in the cost-of-service rate calculation may also change and result in a newly calculated cost-of-service rate that is the same as or greater than the prior cost-of-service rate. Moreover, pipelines receive revenues from cost-of-service rates, negotiated rates, discounted rates, and market-based rates, or a combination thereof. As of December 31, 2018, approximately 59% of our aggregate contracted firm transportation capacity on EGT was subscribed under negotiated rate contracts and approximately 100% of our aggregate contracted firm storage capacity on EGT was subscribed under negotiated rate contracts. As of December 31, 2018, approximately 2% of our aggregate contracted firm transportation capacity on MRT was subscribed under negotiated rate contracts and our aggregated contracted firm storage capacity on MRT was not subscribed under negotiated rate contracts. As of December 31, 2018, approximately 28% and 36% of our aggregate contracted firm transportation capacity on EGT and MRT, respectively, was subscribed under discounted rate contracts. We do not expect rates subject to negotiated rates that are not tied to the cost-of-service rates to be affected by the Revised Policy Statement or any final regulations that may result from the March 15, 2018 issuances. Nor will discounted rates which are below the level of any new maximum rate be affected. With respect to the cost-of-service rates, depending on a detailed review of all of the Partnership’s cost-of-service components and the outcomes of any challenges to our rates by the FERC or our shippers, the NOI, the Final Rule, and the Revised Policy Statement, combined with the reduced corporate federal income tax rate established in the Tax Cuts and Jobs Act, the revenues associated with natural gas transportation services we provide pursuant to cost-of-service based rates may decrease in the future.

The FERC issued a Notice of Inquiry on April 19, 2018 (April 2018 NOI), thereby initiating a review of its policies on certification of natural gas pipelines, including an examination of its long-standing Policy Statement on Certification of New Interstate Natural Gas Pipeline Facilities, issued in 1999, that is used to determine whether to grant certificates for new pipeline projects. We are unable to predict what, if any, changes may be proposed as a result of the April 2018 NOI that will affect our natural gas pipeline business or when such proposals, if any, might become effective. We do not expect that any change in this policy would materially affect our plans and operations.

MRT Rate Case

On June 29, 2018, MRT filed a general rate case with the FERC pursuant to Section 4 of the Natural Gas Act. The rate case proposed, among other things, a general system-wide increase in the maximum tariff rates for all firm and interruptible services offered by MRT, a change in the boundary between the Field and Market zones, a requirement for daily balancing, and changes to the Small Customer service rate schedule. Consistent with the previously mentioned order on rehearing of the FERC’s Revised

Policy Statement, as a pipeline owned by an MLP, MRT also filed to recover an income tax allowance, arguing and providing evidentiary support that it is entitled to an income tax allowance. A number of customers filed notices of intervention and protests, and on July 31, 2018, FERC issued an Order Accepting and Suspending Tariff Records Subject to Refund and Condition and Establishing Hearing and Settlement Judge Procedures and a Technical Conference (July 31 Order). In the July 31 Order, FERC ordered MRT to refile its rate case within 30 days of the date of the July 31 Order to reflect, among other things, the elimination of an income tax allowance from its costs used to calculate MRT's rates pursuant to the Revised Policy Statement. On August 30, 2018, MRT made its filing to comply with the FERC's July 31 Order and also sought rehearing of certain aspects of the July 31, Order, and FERC accepted the filing on December 7, 2018. The elimination of the income tax allowance as mandated by FERC, when coupled with the corresponding elimination of ADIT, had a de minimis impact on MRT's overall cost of service. MRT has, nevertheless, requested rehearing of the July 31 Order, and on September 14, 2018, MRT also filed an appeal of the Revised Policy statement with the United States Court of Appeals for the District of Columbia Circuit, on the grounds that the Revised Policy Statement was, in fact, not being applied as a policy subject to individual pipelines being able to argue and provide evidentiary support for an income tax allowance, but, rather, was being applied as a rule and as an absolute bar to pipelines organized or owned by MLPs being able to recover an income tax allowance.

Market Behavior Rules; Posting and Reporting Requirements

On August 8, 2005, Congress enacted the EPAct of 2005. Among other matters, the EPAct of 2005 amended the NGA to add an anti-manipulation provision that makes it unlawful for any entity to engage in prohibited behavior in contravention of rules and regulation to be prescribed by FERC and, furthermore, provides FERC with additional civil penalty authority. On January 19, 2006, FERC issued Order No. 670, a rule implementing the anti-manipulation provisions of the EPAct of 2005. The rules make it unlawful for any entity, directly or indirectly in connection with the purchase or sale of natural gas subject to the jurisdiction of FERC or the purchase or sale of transportation services subject to the jurisdiction of FERC, to (1) use or employ any device, scheme or artifice to defraud; (2) to make any untrue statement of material fact or omit to make any such statement necessary to make the statements not misleading; or (3) to engage in any act or practice that operates as a fraud or deceit upon any person. The anti-manipulation rules apply to interstate gas pipelines and storage companies and intrastate gas pipelines and storage companies that provide interstate services, such as Section 311 service, as well as otherwise non-jurisdictional entities to the extent the activities are conducted "in connection with" gas sales, purchases or transportation subject to FERC jurisdiction. The anti-manipulation rules do not apply to activities that relate only to intrastate or other non-jurisdictional sales or gathering to the extent such transactions do not have a "nexus" to jurisdictional transactions. The EPAct of 2005 also amends the NGA and the NGPA to give FERC authority to impose civil penalties for violations of these statutes and FERC's regulations, rules and orders, up to approximately $1.27 million per day per violation for violations occurring after August 8, 2005. This maximum penalty authority established by statute will continue to be adjusted periodically for inflation. In connection with this enhanced civil penalty authority, FERC issued a revised policy statement on enforcement to provide guidance regarding the enforcement of the statutes, orders, rules and regulations it administers, including factors to be considered in determining the appropriate enforcement action to be taken. If we fail to comply with all applicable FERC-administered statutes, rules, regulations and orders, we could be subject to substantial penalties and fines. In addition, the CFTC is directed under the Commodities Exchange Act, or CEA, to prevent price manipulations for the commodity and futures markets, including the energy futures markets. Pursuant to the Dodd-Frank Act and other authority, the CFTC has adopted anti-market manipulation regulations that prohibit fraud and price manipulation in the commodity and futures markets. The CFTC also has statutory authority to seek civil penalties of up to the greater of $1.2 million or triple the monetary gain to the violator for violations of the anti-market manipulation sections of the CEA.

The EPAct of 2005 also added Section 23 to the NGA, authorizing FERC to facilitate price transparency in markets for the sale or transportation of physical natural gas in interstate commerce. In 2007, FERC took steps to enhance its market oversight and monitoring of the natural gas industry by issuing several rulemaking orders designed to promote gas price transparency and to prevent market manipulation. In December 2007, FERC issued a final rule on the annual natural gas transaction reporting requirements, as amended by subsequent order on rehearing, or Order No. 704. Order No. 704 requires buyers and sellers of annual quantities of natural gas of 2,200,000 MMBtu or more, including entities not otherwise subject to FERC's jurisdiction, to provide by May 1 of each year an annual report to FERC describing their aggregate volumes of natural gas purchased or sold at wholesale in the prior calendar year to the extent such transactions utilize, contribute to or may contribute to the formation of price indices. Order No. 704 also requires market participants to indicate whether they report prices to any index publishers and, if so, whether their reporting complies with FERC's policy statement on price reporting. In June 2010, FERC issued the last of its three orders on rehearing and clarification further clarifying its requirements.

Intrastate Natural Gas Pipeline and Storage Regulation

In Oklahoma, our intrastate pipeline system (EOIT) is subject to limited regulation by the OCC. Oklahoma has a non-discriminatory access requirement, which is subject to a complaint-based review. EOIT's rates and terms of service are not subject to regulation by the OCC.

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Intrastate natural gas transportation is largely regulated by the state in which the transportation takes place. An intrastate natural gas pipeline system may transport natural gas in interstate commerce provided that the rates, terms and conditions of such transportation service comply with FERC's regulations under Section 311 of the NGPA and Part 284 of the FERC's regulations. The NGPA regulates, among other things, the provision of transportation and storage services by an intrastate natural gas pipeline on behalf of an interstate natural gas pipeline or a LDC served by an interstate natural gas pipeline. Under Section 311, rates charged for transportation must be fair and equitable, and amounts collected in excess of fair and equitable rates are subject to refund with interest. The rates under Section 311 are maximum rates and an intrastate pipeline may agree to discount contractual rates at or below such maximum rates. Rates for service pursuant to Section 311 of the NGPA are generally subject to review and approval by FERC at least once every five years. Should the FERC determine not to authorize rates equal to or greater than our currently approved Section 311 rates, our business may be adversely affected.
Failure to observe the service limitations applicable to transportation services provided under Section 311, failure to comply with the rates approved by FERC for Section 311 service, or failure to comply with the terms and conditions of service established in the pipeline's FERC-approved Statement of Operating Conditions could result in the assertion of federal NGA jurisdiction by FERC and/or the imposition of administrative, civil and criminal penalties, as described in the "—Interstate Natural Gas Pipeline Regulation" section above.

EOIT currently has two zones under its Section 311 transportation rate structure—an East Zone and a West Zone. For Section 311 service, EOIT may charge up to its maximum established zonal East and West interruptible transportation rates for interruptible transportation in one zone or cumulative maximum rates for transportation in both zones. Finally, EOIT may charge the applicable fixed zonal fuel percentage(s) for the fuel used in transporting natural gas under Section 311 on our system. The fixed zonal fuel percentages are the same for firm and interruptible Section 311 services.

Under FERC Order No. 735, intrastate pipelines providing transportation services under Section 311 of the NGPA are required to report on a quarterly basis via FERC Form 549D more detailed information and storage transaction information, including: rates charged by the pipeline under each contract; receipt and delivery points and zones or segments covered by each contract; the quantity of natural gas the shipper is entitled to transport, store, or deliver; the duration of the contract; and whether there is an affiliate relationship between the pipeline and the shipper. Order No. 735 further requires that such information must be supplied through an electronic reporting system and will be posted on FERC's website, and that such quarterly reports may not contain information redacted as privileged. FERC promulgated this rule after determining that such transactional information would help shippers make more informed purchasing decisions and would improve the ability of both shippers and FERC to monitor actual transactions for evidence of market power or undue discrimination. Order No. 735 also extends FERC's periodic review of the rates charged by the subject pipelines from three to five years. In Order No. 735-A, FERC generally reaffirmed Order No. 735 requiring Section 311 to report on a quarterly basis storage and transportation transactions containing specific information for each transaction, aggregated by contract. Our intrastate storage assets at the Wetumka Storage Field offer both fee-based firm and interruptible storage services under Section 311 of the NGPA pursuant to terms and conditions specified in our statement of operating conditions for gas storage at market-based rates. Our intrastate Stuart Storage Field currently is used exclusively to provide intrastate storage service, even though FERC previously authorized the use of that storage facility for Section 311 interstate service.

Natural Gas Gathering and Processing Regulation

Section 1(b) of the NGA exempts natural gas gathering and processing facilities from the jurisdiction of the FERC. Although the FERC has not made formal determinations with respect to all of our facilities we consider to be gathering facilities, management believes that our natural gas gathering pipelines meet the traditional tests that the FERC has used to determine that a pipeline is a gathering pipeline and is therefore not subject to FERC's NGA jurisdiction. The distinction between FERC-regulated transmission services and federally unregulated gathering services, however, has been the subject of substantial litigation, and the FERC determines whether facilities are gathering facilities on a case-by-case basis, so the classification and regulation of our gathering facilities is subject to change based on future determinations by the FERC, the courts or Congress. If the FERC were to consider the status of an individual facility and determine that the facility and/or services provided by it are not exempt from FERC regulation under the NGA and that the facility provides interstate service, the rates for, and terms and conditions of, services provided by such facility would be subject to regulation by the FERC under the NGA or the NGPA. Such regulation could decrease revenue, increase operating costs, and, depending upon the facility in question, could adversely affect our results of operations and cash flows. In addition, if any of our facilities were found to have provided services or otherwise operated in violation of the NGA or NGPA, this could result in the imposition of civil penalties as well as a requirement to disgorge charges collected for such service in excess of the rate established by the FERC.

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States may regulate gathering pipelines. State regulation of gathering facilities generally includes various safety, environmental and, in some circumstances, requirements prohibiting undue discrimination, and in some instances complaint-based rate regulation. Our gathering operations may be subject to ratable take and common purchaser statutes in the states in which they operate. The ratable take statutes generally require gatherers to take, without undue discrimination, natural gas production that may be tendered to the gatherer for handling. Similarly, common purchaser statutes generally require gatherers to purchase without undue discrimination as to source of supply or producer. These statutes are designed to prohibit discrimination in favor of one producer over another producer or one source of supply over another source of supply. These statutes have the effect of restricting our right as an owner of gathering facilities to decide with whom we contract to purchase or transport natural gas.

Our gathering operations could be adversely affected should they be subject in the future to the application of state or federal regulation of rates and services. Our gathering operations could also be subject to additional safety and operational regulations relating to the design, construction, testing, operation, replacement and maintenance of gathering facilities. Additional rules and legislation pertaining to these matters are considered or adopted from time to time. We cannot predict what effect, if any, such changes might have on its operations, but the industry could be required to incur additional capital expenditures and increased costs depending on future legislative and regulatory changes.

Sales of Natural Gas

The price at which we buy and sell natural gas currently is not subject to federal regulation and, for the most part, is not subject to state regulation. However, as noted above, with regard to our physical purchases and sales of these energy commodities, and any related hedging activities that we undertake, we are required to observe anti-market manipulation laws and related regulations enforced by FERC and/or the CFTC. Should we violate the anti-market manipulation laws and regulations, we could also be subject to related third-party damage claims by, among others, market participants, sellers, royalty owners and taxing authorities.

Our sales of natural gas are affected by the availability, terms and cost of pipeline transportation. As noted above, the price and terms of access to pipeline transportation are subject to extensive federal and state regulation. FERC is continually proposing and implementing new rules and regulations affecting those segments of the natural gas industry, most notably interstate natural gas transmission companies that remain subject to FERC jurisdiction. These initiatives also may affect the intrastate transportation of natural gas under certain circumstances. The stated purpose of many of these regulatory changes is to promote competition among the various sectors of the natural gas industry. We cannot predict the ultimate impact of these regulatory changes on our natural gas marketing operations.

Interstate Crude Oil Gathering Regulation

Crude oil gathering pipelines that transport crude oil in interstate commerce may be regulated as common carriers by FERC under the ICA, the Energy Policy Act of 1992 and the rules and regulations promulgated under those laws. Our crude oil gathering systems in the Williston Basin transport crude oil in interstate commerce. The ICA and FERC regulations require that rates for interstate service pipelines that transport crude oil and refined petroleum products (collectively referred to as “petroleum pipelines”) and certain other liquids, be just and reasonable and are to be non-discriminatory or not confer any undue preference upon any shipper. FERC regulations also require interstate common carrier petroleum pipelines to file with FERC and publicly post tariffs stating their interstate transportation rates and terms and conditions of service. Under the ICA, FERC or interested persons may challenge existing or changed rates or services. The FERC is authorized to investigate such charges and may suspend the effectiveness of a new rate for up to seven months. A successful rate challenge could result in a common carrier paying refunds together with interest for the period that the rate was in effect. FERC may also order a pipeline to change its rates and may require a common carrier to pay shippers reparations for damages sustained for a period up to two years prior to the filing of a complaint.

If our rate levels were investigated by FERC, the inquiry could result in a comparison of our rates to those charged by others or to an investigation of our costs, including:

- the overall cost of service, including operating costs and overhead;
- the allocation of overhead and other administrative and general expenses to the regulated entity;
- the appropriate capital structure to be utilized in calculating rates;
- the appropriate rate of return on equity and interest rates on debt;
- the rate base, including the proper starting rate base;
- the throughput underlying the rate; and
- the proper allowance for federal and state income taxes.

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For some time now, FERC has been issuing regulatory assurances that necessarily balance the anti-discrimination and undue preference requirements of common carriage with the expectations of investors in new and expanding petroleum pipelines. There is an inherent tension between the requirements imposed upon a common carrier and the need for owners of petroleum pipelines to be able to enter into long-term, firm contracts with shippers willing to make the commitments which underpin such large capital investments. For example, FERC has found that shipper contract rates are not per se violations of the duty of non-discrimination, provided that such rates are available to all similarly-situated shippers. In the same vein, FERC has approved varying term commitments with tiered rate discounts on the basis that committed shippers were not similarly situated with uncommitted shippers and further that different types of committed shippers were not similarly situated with each other if their commitment level materially differed. FERC has also found that shippers making certain capacity commitments to the pipeline can take advantage of priority or firm service, which is service that is not subject to typical capacity allocation requirements, so long as any interested shipper has an equal opportunity to make such a commitment to the carrier. FERC’s solution has been to allow carriers to hold an “open season” prior to the in-service date of a pipeline, during which time interested shippers can make commitments to the proposed pipeline project. Throughput commitments from interested shippers during an open season can be for firm service or for non-firm service. Typically, such an open season is for a 30-day period, must be publicly announced, and culminates in interested parties entering into transportation agreements with the carrier. Under FERC precedent, a carrier typically may reserve up to 90% of available capacity for the provision of firm or priority service to shippers making a commitment. At least 10% of capacity ordinarily is reserved for uncommitted shippers, i.e., “walk-up” shippers.

Under the ICA, FERC does not have authority over the siting of oil transportation assets nor over the abandonment of facilities or services. Accordingly, no approval from FERC is necessary prior to placing a new petroleum pipeline project in operation. However, FERC highly encourages carriers to file a Petition for Declaratory Order to seek regulatory assurances for key terms of service offered during an open season. As long as the shippers on our Bakken crude oil gathering system move oil in interstate commerce, our crude oil gathering system will not be regulated by the North Dakota Public Service Commission.

FERC utilizes an indexing rate methodology which, as currently in effect, allows common carriers to change their rates within prescribed ceiling levels that are tied to changes in the Producer Price Index. The indexing methodology is applicable to existing rates, with the exclusion of market-based rates. FERC’s indexing methodology is subject to review every five years. During the five-year period commencing July 1, 2016 and ending June 30, 2021, common carriers charging indexed rates are permitted to adjust their indexed ceilings annually by the Producer Price Index plus 1.23%. Many existing pipelines, including our Williston Basin crude oil gathering systems, utilize the FERC oil index to change transportation rates annually every July 1. With respect to oil and refined products pipelines subject to FERC jurisdiction, the Revised Policy Statement requires the pipeline to reflect the impacts to its cost of service from the Revised Policy Statement and the Tax Cuts and Jobs Act on the Page 700 of FERC Form No. 6. This information will be used by FERC in its next five-year review of the oil pipeline index to generate the index level to be effective July 1, 2021, thereby including the effect of the Revised Policy Statement and the Tax Cuts and Jobs Act in the determination of indexed rates prospectively, effective July 1, 2021. FERC’s establishment of a just and reasonable rate, including the determination of the appropriate oil pipeline index, is based on many components, and tax-related changes will affect two such components, the allowance for income taxes and the amount for ADIT, while other pipeline costs also will continue to affect FERC’s determination of the appropriate pipeline index. Accordingly, depending on FERC’s application of its indexing rate methodology for the next five-year term of index rates, the Revised Policy Statement and tax effects related to the Tax Cuts and Jobs Act may impact our revenues associated with any transportation services we may provide pursuant to cost-of-service based rates, including indexed rates, beginning July 1, 2021.

Intrastate Crude Oil and Condensate Gathering Regulation

Our crude oil and condensate gathering system in the Anadarko Basin is located in Oklahoma and is subject to limited regulation by the OCC. Crude oil and condensate gathering systems are common carriers under Oklahoma law and are prohibited from unjust or unlawful discrimination in favor of one customer over another. Additional rules and legislation pertaining to these matters are considered or adopted from time to time. Our crude oil and condensate gathering operations could be adversely affected should they be subject in the future to the application of state or federal regulation of rates and services.

Safety and Health Regulation

Pipeline Safety

Our pipeline facilities are subject to regulation under federal pipeline safety statutes and comparable state statutes. Federal pipeline safety statutes include the Natural Gas Pipeline Safety Act of 1968 (NGPSA), which provides for safety requirements in the design, construction, operation and maintenance of natural gas pipeline facilities, and the Hazardous Liquid Pipeline Safety

Act of 1979 (HLPSA), which provides for safety requirements for the design, construction, operation and maintenance of hazardous liquids pipelines facilities, including NGL and crude oil pipelines. The NGPSA and the HLPSA have been subject to a number of amendments and supplements including the Pipeline Safety Act of 1992, the Accountable Pipeline Safety and Partnership Act of 1996, the Pipeline Safety Improvement Act of 2002, the Pipeline Inspection, Protection, Enforcement and Safety Act of 2006 (the PIPES Act), the Pipeline Safety, Regulatory Certainty, Job Creation Act of 2011 (the 2011 Pipeline Safety Act), and the Securing America's Future Energy Protecting our Infrastructure of Pipelines and Enhancing Safety Act.

We are regulated under federal pipeline safety statutes by DOT through the Pipeline and Hazardous Materials Safety Administration (PHMSA). PHMSA sets and enforces pipeline safety regulations and standards. PHMSA's enforcement authority includes the ability to assess civil penalties for violations of pipeline safety regulations. PHMSA has civil penalty authority of up to $209,002 per day per violation, with a maximum of $2,090,022 million for any related series of violations. In addition to governing the design, construction, operation and maintenance of natural gas and hazardous liquids pipeline facilities, PHMSA's regulations require the following for certain pipelines: an inspection and maintenance plan; an integrity management program, which includes the determination of pipeline integrity risks and periodic assessments of pipeline segments in high consequence areas; a drug and alcohol testing program; an operator qualification program, which includes training for personnel performing tasks covered by pipeline safety rules; a public awareness program, which provides relevant information to residents, public officials and emergency responders; and a control room management plan.

As part of regulating pipeline safety, PHMSA periodically promulgates pipeline safety regulations. For example, in December 2016, PHMSA published an interim final rule providing pipeline safety regulations for underground natural gas storage. PHMSA also periodically publishes advisory bulletins. For example, in January 2011, PHMSA published an advisory bulletin stating that operators of natural gas and hazardous liquid pipeline facilities should perform detailed threat and risk analyses that integrate accurate data and information from their entire pipeline system and to utilize these risk analyses in the identification of appropriate assessment methods and preventive and mitigative measures and, in May 2012, PHMSA published an advisory bulletin stating that operators of gas and hazardous liquid pipeline facilities should verify records relating to operating specifications for maximum allowable operating pressure (MAOP) for gas pipelines and maximum operating pressure (MOP) for hazardous liquid pipelines. PHMSA has implemented an enhanced inspection program related to these new standards, and PHMSA has announced that it intends to issue a final rule in 2019 that may impose additional requirements.

Federal pipeline safety regulations contain an exemption that applies to gathering lines in certain rural locations. A substantial portion of our gathering lines qualify for that exemption and are currently not regulated under federal law. However, in May 2016, PHMSA proposed rules that would, if adopted, impose more stringent requirements for certain gas lines. Among other things, the proposed rulemaking would extend certain of PHMSA's current regulatory safety programs for gas pipelines beyond "high consequence areas" to cover gas pipelines found in newly defined "moderate consequence areas" that contain as few as five dwellings within the potential impact area and would also require gas pipelines installed before 1970 that are currently exempted from certain pressure testing obligations to be tested to determine their maximum allowable operating pressures (MAOP). Other new requirements proposed by PHMSA under rulemaking would require pipeline operators to: report to PHMSA in the event of certain MAOP exceedances; strengthen PHMSA integrity management requirements; consider seismicity in evaluating threats to a pipeline; conduct hydrostatic testing for all pipeline segments manufactured using longitudinal seam welds; and use more detailed guidance from PHMSA in the selection of assessment methods to inspect pipelines. The proposed rulemaking also seeks to impose a number of requirements on natural gas gathering lines. PHMSA has announced its intention to divide the proposed rule into three parts and issue three separate final rulemakings in 2019. Part I is expected to address the expansion of risk assessment and MAOP requirements (expected issuance in March 2019); Part II is expected to address the expansion of integrity management program regulations (expected issuance in June 2019); and Part III is expected to expand the regulation of gas gathering lines (expected issuance in August 2019). We cannot predict whether PHMSA will meet these deadlines or what form these final rules may take. Separately, in January 2017, PHMSA finalized regulations for hazardous liquid pipelines that significantly extend and expand the reach of certain PHMSA integrity management requirements (i.e., periodic assessments, leak detection and repairs), regardless of the pipeline's proximity to a high consequence area. The final rule would also impose new reporting requirements for certain unregulated pipelines, including all hazardous liquid gathering lines. However, implementation of this rule has been delayed as a result of the change in presidential administrations, and the final rule is not expected to be published by the Federal Register until some time in the first half of 2019.

States are largely preempted by federal law from regulating pipeline safety but may assume responsibility for administering and enforcing intrastate pipeline regulations at least as stringent as the federal standards. For example, the OCC administers the intrastate pipeline safety program in Oklahoma, and the Texas Railroad Commission administers the intrastate pipeline safety program in Texas. In practice, states vary in their authority and capacity to address pipeline safety.

We incur significant costs in complying with federal and state pipeline safety laws and regulations and otherwise administering our pipeline safety program. In 2018, we incurred maintenance capital expenditures and operation and maintenance expenses of

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$54 million under our 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 MAOP or MOP. We currently estimate that we will incur maintenance capital expenditures and operation and maintenance expenses of up to $65 million in 2019 under our pipeline safety program. While we cannot predict the outcome of legislative or regulatory initiatives, we anticipate that pipeline safety requirements will continue to become more stringent over time. As a result, we may incur significant additional costs to comply with any new pipeline safety laws and regulations associated with our pipeline facilities.

Occupational Health and Safety

In addition to these pipeline safety requirements, we are subject to a number of federal and state laws and regulations, including the Occupational Safety and Health Act of 1970 (OSHA) and comparable state statutes, whose purpose is to protect the safety and health of workers, both generally and within the pipeline industry. In addition, the OSHA hazard communication standard, the EPA community right-to-know regulations under Title III of the Federal Superfund Amendment and Reauthorization Act and comparable state statutes require that information be maintained concerning hazardous materials used or produced in our operations and that this information be provided to employees, state and local government authorities and citizens. We are also subject to OSHA Process Safety Management regulations, which are designed to prevent or minimize the consequences of catastrophic releases of toxic, reactive, flammable or explosive chemicals. These regulations apply to any process which involves a chemical at or above the specified thresholds or any process which involves flammable liquid or gas, pressurized tanks, caverns and wells in excess of 10,000 pounds at various locations. We have an internal program of inspection designed to monitor and enforce compliance with worker safety and health requirements. We are also subject to EPA Risk Management Program (RMP) regulations. In 2017, EPA published a final rule to amend the Accidental Release Prevention Requirements for RMPs. However, this has been subject to both attempted regulatory rollback and litigation. The final status of these rules remains uncertain.

Physical Security

The Department of Homeland Security Appropriation Act of 2007 requires the Department of Homeland Security (DHS) to issue regulations establishing risk-based performance standards for the security of chemical and industrial facilities, including oil and gas facilities that are deemed to present “high levels of security risk.” The DHS issued an interim final rule in April 2007 regarding risk-based performance standards to be attained pursuant to this act and, on November 20, 2007, further issued an Appendix A to the interim rules that establish chemicals of interest and their respective threshold quantities that will trigger compliance with these interim rules. Covered facilities that are determined by DHS to pose a high level of security risk will be required to prepare and submit Security Vulnerability Assessments and Site Security Plans as well as comply with other regulatory requirements, including those regarding inspections, audits, recordkeeping, and protection of chemical-terrorism vulnerability information. Congress reauthorized this program in January 2019, and both Congress and DHS have indicated that they intend to propose revisions to the program’s implementation. We cannot predict what action, if any, Congress or DHS may take at this time.

Cybersecurity

We have become increasingly dependent on the systems, networks and technology that we use to conduct almost all aspects of our business, including the operation of our gathering, processing, transportation and storage assets, the recording of commercial transactions, and the reporting of financial information. We depend on both our own systems, networks, and technology as well as the systems, networks and technology of our vendors, customers and other business partners. We have existing, and continue to develop, systems in place to monitor and address the risk of cybersecurity breaches in our business, operations and control environments. We routinely review and update those systems as the nature of that risk requires. Although we have not experienced any cybersecurity incidents that have significantly impacted any of our business, operations or control environments, a significant cybersecurity incident could have a material effect on our results of operations.

Environmental Regulation

General

Our operations are subject to extensive federal, state and local environmental laws and regulations. These laws and regulations can restrict or impact our business activities in many ways, such as requiring permits to conduct our activities, limiting our emissions of materials into the environment, requiring emissions control equipment, regulating our construction to mitigate harm to protected species, restricting the way we can handle or dispose of waste, and requiring remediation to mitigate the impact of materials discharged into the environment in connection with our current operations or attributable to former operation. Compliance with these laws and regulations increases our capital expenditures and operating expenses, and any failure to comply with these laws

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and regulations could result in the assessment of significant administrative, civil and criminal liabilities, injunctions or other penalties.

We have adopted policies, procedures, and practices to comply with environmental laws and regulations, and we incur significant costs in connection with compliance. In 2018, we incurred approximately $1 million in maintenance capital expenditures in connection with routine environmental compliance with existing laws and regulations, such as environmental controls, monitoring, testing and permit compliance. We expect to incur expenditures for routine environmental compliance with existing laws and regulations of $2 million in 2019. We also incur, and expect to continue to incur, additional costs in connection with spill response and construction. With respect to construction, existing environmental laws and regulations impact the cost of planning, design, permitting, installation, and start-up. While we cannot predict the outcome of legislative or regulatory initiatives, we anticipate that environmental requirements will continue to become more restrictive over time. As a result, we may incur significant additional costs to comply with any new environmental laws and regulations applicable to our operations. For more information, please read Item 1A. "Risk Factors–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 our financial position, results of operations and ability to make cash distributions to unitholders."

Air

Our operations are subject to the federal Clean Air Act (CAA), as amended, and comparable state laws and regulations. These laws and regulations regulate emissions of air pollutants from various industrial sources, including natural gas processing plants and compressor stations, and impose various monitoring and reporting requirements. Such laws and regulations may require that we 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 (including greenhouse gas emissions as discussed below), obtain and strictly comply with air permits containing various emissions and operational limitations or install emission control equipment. For example, in October 2015, the EPA lowered the National Ambient Air Quality Standard (NAAQS) for ozone from 75 to 70 parts per billion, and the agency completed attainment/non-attainment designations in July 2018. Some of our facilities are located in designated non-attainment areas. State implementation of the revised NAAQS could result in stricter permitting requirements, delay or prohibit our ability to obtain such permits and result in increased expenditures for pollution control equipment, the costs of which could be significant. We 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.

Climate Change

There has been a wide-ranging policy debate, both nationally and internationally, regarding climate change, greenhouse gas (GHG) emissions, and possible means for the regulation of GHG emissions. Examples of GHGs include methane, which is a primary component of natural gas, and carbon dioxide, which is a byproduct of the combustion of natural gas as well as the treatment of raw gas before it is delivered to pipelines in a merchantable state of quality. Various laws and regulations exist or are under development to regulate the emission of GHGs, including EPA programs to control GHGs and state actions to develop statewide or regional programs to control GHGs. In addition, the United States Congress has, from time to time, considered adopting legislation to reduce GHG emissions.

The EPA has published findings that certain GHGs may endanger human health, and the EPA has adopted regulations requiring the reporting and permitting of GHG emissions under the CAA. Our operations are subject to those regulations. Those regulations require monitoring and annual reporting of GHG emissions from certain petroleum and natural gas system sources in the U.S., including, among others, gathering and processing facilities which include certain of our operations, and the permitting of large stationary sources of GHG under the CAA's Prevention of

Significant Deterioration and Title V programs. Moreover, in June 2016, the EPA published New Source Performance Standards (NSPS), known as Subpart OOOOa, that requires certain new, modified or reconstructed facilities in the oil and natural gas sector to reduce these methane gas and volatile organic compound emissions through a combination of emission control devices and implementation of enhanced leak detection and repair practices. Following the change in presidential administrations, there have been attempts to modify these regulations, and litigation concerning the regulations is ongoing. As a result, we cannot predict the scope of any final methane regulatory requirements or the cost to comply with such requirements. However, given the historical trend towards stricter regulation of GHG emissions, it is possible that new federal methane rules may be proposed or finalized in the future.

Several states have adopted laws and regulations intended to reduce the emission of GHGs, including through the planned development of GHG emission inventories and/or regional GHG cap and trade programs. The states where our operations are currently located (Alabama, Arkansas, Illinois, Kansas, Louisiana, Mississippi, Missouri, Oklahoma, North Dakota, Tennessee, and Texas) are not among them; however, they may choose to promulgate such rules in the future.

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While we cannot predict the outcome of legislative or regulatory initiatives, we anticipate that initiatives to reduce GHG emissions will continue to develop. The adoption of state or federal legislation or regulatory programs to reduce emissions of GHGs, including methane and carbon dioxide, could require us to incur increased operating costs, such as costs to purchase and operate emissions monitoring and control systems, to acquire emissions allowances or comply with new regulatory or reporting requirements. Any such legislation or regulatory programs could also increase the cost of consuming natural gas and other hydrocarbons, and thereby reduce demand for, the natural gas we gather, treat and transport. Consequently, legislation and regulatory programs to reduce emissions of GHGs could have an adverse effect on our business, financial condition and results of operations. 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. However, recent activism directed at shifting funding away from companies with energy-related assets could result in limitations or restrictions on certain sources of funding for the energy sector.

National Environmental Policy Act (NEPA)

NEPA provides for an environmental impact assessment process in connection with certain projects that involve federal lands or require approvals by federal agencies. The NEPA process implicates a number of other environmental laws and regulations, including the Endangered Species Act, Migratory Bird Treaty Act, Rivers and Harbors Act, Clean Water Act, Bald and Golden Eagle Protection Act, Fish and Wildlife Coordination Act, Marine Mammal Protection Act and National Historic Preservation Act. The NEPA review process can be lengthy and subjective and can cause delays in projects. Our projects that are subject to the NEPA can include pipeline construction and pipeline integrity projects that involve federal lands or require approvals by federal agencies. Ineffective implementation of the NEPA process could cause significant impacts to such projects in the form of delays or significant compliance costs.

Protected 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 we conduct operations, or if additional species in those areas become subject to protection, our operations and development projects, particularly pipeline projects, could be restricted or delayed, or we could be required to implement expensive mitigation measures. The designation of previously unprotected species, such as the Lesser Prairie Chicken, as threatened or endangered in areas where our operations are conducted could cause us to incur increased costs arising from species protection measures or could result in limitations on our customer’s exploration and production activities that could have an adverse impact on demand for our services. Portions of the basins we serve are designated as critical or suitable habitat for threatened and endangered species. If additional portions of the basins we serve were designated as critical or suitable habitat for threatened and endangered species, it could adversely impact the cost of operating our systems and of constructing new facilities. Management believes that we are in material compliance with all applicable laws providing special protection to designated species.

Hazardous Substances and Waste

Our operations are subject to federal and state environmental laws and regulations relating to the management and release of hazardous substances, solid and hazardous wastes, and petroleum hydrocarbons. For instance, our operations are subject to the Comprehensive Environmental Response, Compensation and Liability Act of 1980 (CERCLA or Superfund), as amended, and comparable state cleanup laws that 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. These persons include current and prior owners or operators of the site where the release occurred and companies that disposed or arranged for the disposal of the hazardous substances found at the site. Under CERCLA, these persons may, jointly and severally, be subject to strict liability for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources and for the costs of certain health studies. CERCLA also authorizes the EPA and, in some instances, third parties to act in response to threats to the public health or the environment and to seek to recover the costs they incur from the responsible classes of persons. It is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by hazardous substances or other pollutants released into the environment. Because we utilize various products and generate wastes that are considered hazardous substances for purposes of CERCLA, we could be subject to liability for the costs of cleaning up and restoring sites where those substances have been released to the environment.

Our operations also generate solid and hazardous wastes that are subject to the federal Resource Conservation and Recovery Act of 1976 (RCRA) as well as comparable state laws. While RCRA regulates both solid and hazardous wastes, it imposes detailed requirements for the handling, storage, treatment and disposal of hazardous waste. RCRA currently exempts many natural gas

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gathering and field processing wastes from classification as hazardous waste. However, it is possible that these wastes, which could include wastes currently generated during our operations, will in the future be designated as “hazardous wastes” and therefore be subject to more rigorous and costly disposal requirements. Such changes to the law could have an impact on our capital expenditures and operating expenses. For example, in December 2016, the EPA and environmental groups entered into a consent decree to address the EPA’s alleged failure to timely assess its RCRA Subtitle D criteria regulations exempting certain exploration and production related oil, natural gas and NGL wastes from regulation as hazardous wastes under RCRA. The consent decree requires the EPA to propose a rulemaking no later than March 15, 2019 for revision of certain Subtitle D criteria regulations pertaining to oil, natural gas and NGL wastes or to sign a determination that revision of the regulations is not necessary. We cannot predict whether the EPA will meet this deadline. If the EPA proposes rulemaking for revised oil and natural gas regulations, the consent decree requires that the EPA take final action following notice and comment rulemaking no later than July 15, 2021. Any such change could result in an increase in the costs to manage and dispose of wastes, which could increase the costs of our operators’ operations. Further, these currently RCRA-exempt oil and gas exploration and production wastes may still be regulated under state law or RCRA’s less stringent solid waste requirements. The transportation of natural gas in pipelines may also generate some hazardous wastes that are subject to RCRA or a comparable state law regime.

Water

Our operations are subject to the federal Clean Water Act (CWA) and analogous state laws and regulations. These laws and regulations impose detailed requirements and strict controls regarding the discharge of pollutants into state and federal waters. The discharge of pollutants, including discharges resulting from a spill or leak, is prohibited unless authorized by a permit or other agency approval. In addition, the CWA and analogous state laws require individual permits or coverage under general permits for discharges of storm water runoff from certain types of facilities. These permits may require us to monitor and sample the storm water runoff from some of our facilities. The CWA and regulations implemented thereunder also prohibit discharges of dredged and fill material in wetlands and other waters of the United States unless authorized by an appropriately issued permit. In June 2015, the EPA and United States Army Corps of Engineers (the “Corps”) published a final rule attempting to clarify the federal jurisdictional reach over WOTUS. Several legal challenges to the rule followed, along with attempts to stay implementation following the change in presidential administrations. Currently, the WOTUS rule is active in 22 states and enjoined in 28 states. However, in December 2018, the EPA and the Corps proposed changes to regulations under the CWA that would provide discrete categories of jurisdictional waters and tests for determining whether a particular waterbody meets any of those classifications. Several groups have already announced their intentions to challenge the proposed WOTUS replacement rule. Therefore, the scope of jurisdiction under the CWA is uncertain at this time. Separately, spill prevention, control and countermeasure requirements of federal laws require appropriate containment berms and similar structures to help prevent the contamination of regulated waters in the event of a hydrocarbon tank spill, rupture or leak. Federal and state regulatory agencies can impose administrative, civil and criminal penalties for non-compliance with many of these requirements.

Certain of our operations are also subject to the Oil Pollution Act (the OPA) which amends and augments oil spill provisions of the Clean Water Act and imposes certain duties and liabilities on certain “responsible parties” related to the prevention of oil spills and damages resulting from such spills in or threatening United States waters or adjoining shorelines. A liable “responsible party” includes the owner or operator of a facility, vessel or pipeline that is a source of an oil discharge or that poses the substantial threat of discharge, or in the case of offshore facilities, the lessee or permittee of the area in which a discharging facility is located. Under OPA, joint and several liability, without regard to fault, may be assigned for oil removal costs and a variety of public and private damages. Although defenses exist to the liability imposed by OPA, they are limited. In the event of an oil discharge or substantial threat of discharge, we may be liable for costs and damages.

Hydraulic Fracturing

Hydraulic fracturing is an important and common practice that is used to stimulate production of hydrocarbons from tight formations. The process involves the injection of water, sand and chemicals under pressure into the formation to fracture the surrounding rock and stimulate production. The process is regulated by state agencies, typically the state's commission that regulates oil and gas production. A number of federal agencies, including the EPA and the U.S. Department of Energy, have analyzed, or have been requested to review, a variety of environmental issues associated with hydraulic fracturing. For example, the EPA finalized regulations under the CWA in June 2016 prohibiting wastewater discharges from hydraulic fracturing and certain other natural gas operations to publicly owned wastewater treatment plants. In addition, some states have adopted, and other states are considering adopting, regulations that could impose more stringent disclosure and/or well construction requirements on hydraulic fracturing operations.

State and federal regulatory agencies also recently focused on a possible connection between the operation of injection wells used for oil and gas wastewater 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

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United States Geological Survey identified six states with the most significant hazards from induced seismicity: Oklahoma, Kansas, Texas, Colorado, New Mexico, and Arkansas. In light of these concerns, some state regulatory agencies have modified their regulations or issued orders to address induced seismicity through restrictions on disposal wells or enhanced well construction and monitoring requirements. 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 wastewater disposal process.

If new laws or regulations that significantly restrict hydraulic fracturing or wastewater disposal wells are adopted, such laws could lead to greater opposition to, and litigation concerning, related oil and gas producing activities and to operational delays or increased operating costs for our customers, which in turn could reduce the demand for our services. For more information, please read Item 1A. “Risk Factors–Increased regulation of hydraulic fracturing and waste water injection wells could result in reductions or delays in natural gas production by our customers, which could adversely affect our financial position, results of operations and ability to make cash distributions to unitholders.”

Our Employees

As of December 31, 2018, we employ approximately 1,705 employees with an additional 89 individuals providing services to us as seconded employees of OGE Energy. Personnel remain seconded to the Partnership, subject to certain termination rights of the Partnership and OGE Energy, in order to continue their participation in OGE Energy’s defined benefit and retiree medical plans. Please read Item 13. “Certain Relationships and Related Transactions, and Director Independence—Employee Secondment” for a description of the agreements governing these relationships.

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Item 1A. Risk Factors

You should carefully consider each of the following risks and all of the other information contained in this Annual Report on Form 10-K in evaluating us and our common units. Some of these risks relate principally to our business and the industry in which we operate, while others relate principally to tax matters, ownership of our common units, our preferred units and securities markets generally. If any of the following risks were actually to occur, our business, financial position or results of operations could be materially adversely affected. In that case, we might not be able to pay the minimum quarterly distribution on our common units, or the trading price of our common units could decline.

Risks Related to Our Business

We may not have sufficient cash from operations following the establishment of cash reserves and payment of fees and expenses, including cost reimbursements to our general partner and its affiliates, to enable us to maintain or increase the distributions to holders of our common units.

We may not have sufficient available cash each quarter to enable us to maintain or increase the distributions to holders of our common units. The amount of cash we can distribute on our units principally depends upon the amount of cash we generate from our operations, which will fluctuate from quarter to quarter based on, among other things:

- the fees and gross margins we realize with respect to the volume of natural gas, NGLs and crude oil that we handle;
- 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 we gather, compress, treat, dehydrate, process, fractionate, transport and store;
- 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 our operation and maintenance expenses and general and administrative costs; and
- prevailing economic conditions.

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

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

Our contracts are subject to renewal risks.

As contracts with our existing suppliers and customers expire, we negotiate extensions or renewals of those contracts or enter into new contracts with other suppliers and customers. We 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, our 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 we are unable to renew or replace our expiring contracts on terms that are favorable to us, if at all, or successfully manage our overall contract mix over time, our financial position, results of operations and ability to make cash distributions to unitholders could be adversely affected.

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

For the year ended December 31, 2018, 61% of our natural gas gathered volumes were attributable to the affiliates of Continental, Vine, GeoSouthern, XTO and Tapstone and 51% of our transportation and storage service revenues were attributable to affiliates of CenterPoint Energy, Spire, Continental, AEP and OGE Energy. The loss of all or even a portion of the gathering and processing or transportation and storage services for any of these customers, the failure to extend or replace these contracts or the extension or replacement of these contracts on less favorable terms, as a result of competition or otherwise, could adversely affect our financial position, results of operations and ability to make cash distributions to unitholders.

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

Our businesses are dependent on the drilling and production of natural gas and crude oil. We have no control over the level of drilling activity in our areas of operation, or the amount of natural gas, NGL and crude oil reserves associated with wells connected to our systems. In addition, as the rate at which production from wells currently connected to our system naturally declines over time, our gross margin associated with those wells will also decline. To maintain or increase throughput levels on our gathering and transportation systems and the asset utilization rates at our natural gas processing plants, our customers must continually obtain new natural gas, NGL and crude oil supplies. The primary factors affecting our ability to obtain new supplies of natural gas, NGLs and crude oil and attract new customers to our assets are the level of successful drilling activity near our systems, our ability to compete for volumes from successful new wells and our ability to expand our capacity as needed. If we are not able to obtain new supplies of natural gas, NGLs and crude oil to replace the natural decline in volumes from existing wells, throughput on our gathering, processing, transportation and storage facilities would decline, which could adversely affect our financial position, results of operations and ability to make cash distributions to unitholders. We have 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, NGL 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 our control. Because of these and other factors, even if new reserves are known to exist in areas served by our assets, producers may choose not to develop those reserves. Declines in natural gas, NGL 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, NGL or crude oil prices could also lead producers to shut in production from their existing wells. Sustained reductions in exploration or production activity in our areas of operation could lead to further reductions in the utilization of our systems, which could adversely affect our financial position, results of operations and ability to make cash distributions to unitholders.

In addition, it may be more difficult to maintain or increase the current volumes on our gathering systems and in our processing plants, as several of the formations in the unconventional resource plays in which we operate generally have higher initial production rates and steeper production decline curves than wells in more conventional basins. Should we determine that the economics of our gathering assets do not justify the capital expenditures needed to grow or maintain volumes associated therewith, we may reduce such capital expenditures, which could cause revenues associated with these assets to decline over time.

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Our industry is highly competitive and increased competitive pressure could adversely affect our financial position, results of operations and ability to make cash distributions to unitholders.

We compete with similar enterprises in our respective areas of operation. The principal elements of competition are rates, terms of service and flexibility and reliability of service. Our competitors include large energy companies that have greater financial resources and access to supplies of natural gas, NGLs and crude oil than us. Some of these competitors may expand or construct gathering, processing, transportation and storage systems that would create additional competition for the services we provide to our customers. Excess pipeline capacity in the regions served by our interstate pipelines could also increase competition and adversely impact our ability to renew or enter into new contracts with respect to our available capacity when existing contracts expire. In addition, our 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 ours. Our ability to renew or replace existing contracts with our customers at rates sufficient to maintain current revenues and cash flows could be adversely affected by the activities of our 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 our financial position, results of operations and ability to make cash distributions to unitholders.

We derive a substantial portion of our gross margin from subsidiaries through which we hold a substantial portion of our assets.

We derive a substantial portion of our gross margin from, and hold a substantial portion of our assets through, our subsidiaries. As a result, we depend on distributions from our subsidiaries in order to meet our payment obligations. In general, these subsidiaries are separate and distinct legal entities and have no obligation to provide us with funds for our 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 our subsidiaries' ability to make payments or other distributions to us, and our subsidiaries could agree to contractual restrictions on their ability to make distributions.

Our right to receive any assets of any subsidiary, and therefore the right of our 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 we were a creditor of any subsidiary, our 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 us.

The amount of cash we have available for distribution to our limited partners depends primarily on our cash flow rather than on our profitability, which may prevent us from making distributions, even during periods in which we record net income.

The amount of cash we have available for distribution depends primarily upon our cash flow rather than on profitability. Profitability is affected by non-cash items but cash flow is not. As a result, we may make cash distributions during periods when we record losses for financial accounting purposes and may not make cash distributions during periods when we record net earnings for financial accounting purposes.

We may not be able to recover the costs of our substantial planned investment in capital improvements and additions, and the actual cost of such improvements and additions may be significantly higher than we anticipate.

Our business plan calls for investment in capital improvements and additions. For the year ending December 31, 2019, we estimate that expansion capital could range from approximately $325 million to $425 million and our maintenance capital could range from approximately $105 million to $125 million.

The construction of additions or modifications to our existing systems, and the construction of new midstream assets, involves numerous regulatory, environmental, political and legal uncertainties, many of which are beyond our control and may require the expenditure of significant amounts of capital, which may exceed our 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, our revenues and cash flows may not increase immediately upon the expenditure of funds on a particular project. For instance, if we expand an existing pipeline or construct a new pipeline, the construction may occur over an extended period of time, and we may not receive any material increases in revenues or cash flows until the project is completed. In addition, we 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 our expected investment return, which could adversely affect our financial position, results of operations and ability to make cash distributions to unitholders.

In connection with our capital investments, we 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 we rely on estimates of future production in deciding to construct additions to our 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 our financial position, results of operations and ability to make cash distributions to unitholders. 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 our financial position, results of operations and ability to make cash distributions to unitholders. In addition, the construction of additions to existing gathering and transportation assets may require new rights-of-way prior to construction. Those rights-of-way to connect new natural gas supplies to existing gathering lines may be unavailable and we 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, our financial position, results of operations and ability to make cash distributions to unitholders could be adversely affected.

Natural gas, NGL and crude oil prices are volatile, and changes in these prices could adversely affect our financial position, results of operations and our ability to make cash distributions to unitholders.

Our financial position, results of operations and ability to make cash distributions to unitholders could be negatively affected by adverse changes in the prices of natural gas, NGLs and crude oil depending on factors that are beyond our control. These factors include demand for these commodities, which fluctuates with changes in market and economic conditions and other factors, including the impact of seasonality and weather, general economic conditions, the level of domestic and offshore natural gas production and consumption, the availability of imported natural gas, LNG, 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.

Our natural gas processing arrangements expose us to commodity price fluctuations. In 2018, 6%, 27%, and 67% of our 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 we sell natural gas or NGLs is less than the cost at which we purchase natural gas or NGLs under these arrangements, then our financial position, results of operations and ability to make cash distributions to unitholders could be adversely affected.

At any given time, our overall portfolio of processing contracts may reflect a net short position in natural gas (meaning that we are a net buyer of natural gas) and a net long position in NGLs (meaning that we are a net seller of NGLs). As a result, our financial position, results of operations and ability to make cash distributions to unitholders could be adversely affected to the extent the price of NGLs decreases in relation to the price of natural gas.

We are exposed to credit risks of our customers, and any material nonpayment or nonperformance by our customers could adversely affect our financial position, results of operations and ability to make cash distributions to unitholders.

Some of our customers may experience financial problems that could have a significant effect on their creditworthiness. Severe financial problems encountered by our customers could limit our ability to collect amounts owed to us, or to enforce performance of obligations under contractual arrangements. In addition, many of our 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 our customers' liquidity and limit their ability to make payment or perform on their obligations to us. Furthermore, some of our 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 us. Financial problems experienced by our customers could result in the impairment of our assets, reduction of our operating cash flows and may also reduce or curtail their future use of our products and services, which could reduce our revenues.

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

We have been authorized by the Federal Energy Regulatory Commission, or FERC, to provide transportation and storage services at our facilities at negotiated rates. As of December 31, 2018, approximately 44% of our aggregate contracted firm transportation capacity on EGT and MRT and 45% of our 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 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 our costs increase and we are not able to recover any shortfall of revenue associated with our negotiated rate contracts, the cash flow realized by our systems could decrease and, therefore, the cash we have available for distribution to our unitholders could also decrease.

If third-party pipelines and other facilities interconnected to our gathering, processing or transportation facilities become partially or fully unavailable to us for any reason, our financial position, results of operations and ability to make cash distributions to unitholders could be adversely affected.

We depend upon (i) third-party pipelines to deliver natural gas to, and take natural gas from, our natural gas transportation systems, (ii) third-party pipelines and other facilities to take crude oil from our crude oil gathering systems, and, in some cases, (iii) third-party facilities to process natural gas from our gathering systems. We also depend on third-party facilities to transport and fractionate NGLs that are delivered to the third party at the tailgates of our 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 our processing plants and gathering systems, and a prolonged outage or disruption could ultimately result in a reduction in the volume of natural gas we gather and NGLs we are able to produce. Additionally, we depend on third parties to provide electricity for compression at many of our facilities. Since we do not own or operate any of these third-party pipelines or other facilities, their continuing operation is not within our control. If any of these third-party pipelines or other facilities become partially or fully unavailable to us for any reason, our financial position, results of operations and ability to make cash distributions to unitholders could be adversely affected.

We do not own all of the land on which our pipelines and facilities are located, which could disrupt our operations.

We do not own all of the land on which our pipelines and facilities have been constructed, and we are therefore subject to the possibility of more onerous terms and/or increased costs to retain necessary land use if we do not have valid rights-of-way or if such rights-of-way lapse or terminate. We may obtain the rights to construct and operate our 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 United States. A loss of these rights, through our inability to renew right-of-way contracts or otherwise, could cause us to cease operations temporarily or permanently on the affected land, increase costs related to the construction and continuing operations elsewhere, and adversely affect our financial position, results of operations and ability to make cash distributions to unitholders.

We conduct a portion of our operations through joint ventures, which subject us to additional risks that could adversely affect the success of these operations and our financial position, results of operations and ability to make cash distributions to unitholders.

We conduct a portion of our 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. We 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 our control. If these parties do not satisfy their obligations under these arrangements, our business may be adversely affected.

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

- our joint venture partners may share certain approval rights over major decisions;
- our joint venture partners may not pay their share of the joint venture's obligations, leaving us liable for their shares of joint venture liabilities;

- we may be unable to control the amount of cash we will receive from the joint venture;
- we may incur liabilities as a result of an action taken by our joint venture partners;
- we may be required to devote significant management time to the requirements of and matters relating to the joint ventures;
- our insurance policies may not fully cover loss or damage incurred by both us and our joint venture partners in certain circumstances;
- our joint venture partners may be in a position to take actions contrary to our instructions or requests or contrary to our policies or objectives; and
- disputes between us and our joint venture partners may result in delays, litigation or operational impasses.

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

We own a 50% ownership interest in SESH. The remaining 50% ownership interests are held by Enbridge Inc. As of December 31, 2018, CenterPoint Energy owns 54.0% of our common units, 100% of our Series A Preferred Units and a 40% economic interest in our general partner. Pursuant to the terms of the limited liability company agreement of SESH, as amended (the SESH LLC Agreement), if, at any time, CenterPoint Energy has a right to receive less than 50% of our distributions through its interests in us and in our general partner, or does not have the ability to exercise certain control rights, Enbridge Inc. could have the right to purchase our 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 our 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 we account for under the equity method is our investment in SESH. If we enter into additional joint ventures, we 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, we have goodwill of $98 million as a result of the acquisition of Velocity Holdings, LLC in the fourth quarter of 2018 and Align Midstream, LLC in the fourth quarter of 2017.

We could experience future events or circumstances that result in an impairment of long-lived assets, including intangible assets, equity method investments, or goodwill. If we recognize an impairment, we 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 our results of operations and our ability to satisfy the financial ratios or other covenants under our existing or future debt agreements.

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Our 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 our financial position, results of operations and our ability to make cash distributions to unitholders.

Our 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 our operations. A natural disaster or other hazard affecting the areas in which we operate could adversely affect our results of operations. We are not fully insured against all risks inherent in our business. We currently have general liability and property insurance in place to cover certain of our facilities in amounts that we consider appropriate. Such policies are subject to certain limits and deductibles. We have business interruption insurance coverage for some but not all of our 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 our facilities may not be sufficient to restore the loss or damage without adversely affecting our financial position, results of operations and our ability to make cash distributions to unitholders.

The use of derivative contracts by us and our subsidiaries in the normal course of business could result in financial losses that could adversely affect our financial position, results of operations and our ability to make cash distributions to unitholders.

We and our subsidiaries periodically use derivative instruments, such as swaps, options, futures and forwards, to manage our commodity and financial market risks. We and our 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 our results of operations.

Our business is dependent on our 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. Our 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 our ability to manage and operate our business. If we are unable to successfully attract and retain an appropriately qualified workforce, our results of operations could be negatively affected.

As of December 31, 2018, we have 89 employees who are participants under OGE Energy's defined benefit and retiree medical plans, who are seconded to the Partnership, subject to certain termination rights of the Partnership and OGE Energy. If seconding is terminated, employees of OGE Energy that we determine to hire are under no obligation to accept our offer of employment on the terms we provide, or at all.

Our ability to grow is dependent in part on our ability to access external financing sources on acceptable terms.

Our operating subsidiaries distribute all of their available cash to us, and we distribute all of our available cash to our unitholders. As a result, we and our operating subsidiaries 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 we or our operating subsidiaries are unable to finance growth externally or through internally generated cash flows, our

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and our operating subsidiaries' cash distribution policy may significantly impair our and our operating subsidiaries' ability to grow. In addition, because we and our operating subsidiaries distribute all available cash, our and our operating subsidiaries' growth may not be as fast as businesses that reinvest their available cash to expand ongoing operations. For further information related to distributions of available cash, please see Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations."

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

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

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

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

From time to time, we have made, and we intend 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;
- we may assume liabilities that were not disclosed to us, that exceed our estimates, or for which our rights to indemnification from the seller are limited;
- we 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 our ongoing businesses, distract management, divert resources and make it difficult to maintain our current business standards, controls and procedures.

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

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

As of December 31, 2018, we 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, we had $649 million outstanding under our commercial paper program and $500 million outstanding under our 2019 Notes, excluding unamortized debt expense. We have a $1.75 billion Revolving Credit Facility for working capital, capital expenditures and other partnership purposes, including acquisitions, with approximately $250 million in borrowings outstanding and $848 million remaining available as of February 1,

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2019. We have the ability to incur additional debt, subject to limitations in our credit facilities. 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, 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;
- our debt level will make us more vulnerable to competitive pressures or a downturn in our business or the economy generally; and
- our debt level may limit our flexibility in responding to changing business and economic conditions.

Our and our operating subsidiaries' ability to service our and their debt will depend upon, among other things, their 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 our and their control. If operating results are not sufficient to service our or our operating subsidiaries' current or future indebtedness, we and they 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. Please see Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources."

Our credit facilities contain operating and financial restrictions, including covenants and restrictions that may be affected by events beyond our control, which could adversely affect our financial condition, results of operations and ability to make cash distributions to our unitholders.

Our credit facilities contain customary covenants that, among other things, limit our ability to:

- permit our 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 our business.

Our credit facilities also require us to maintain certain financial ratios. Our ability to meet those financial ratios can be affected by events beyond our control, and we cannot assure you that we will meet those ratios. In addition, our credit facilities contain events of default customary for agreements of this nature.

Our ability to comply with the covenants and restrictions contained in our credit facilities may be affected by events beyond our control, including prevailing economic, financial and industry conditions. If market or other economic conditions deteriorate, our ability to comply with these covenants may be impaired. If we violate any of the restrictions, covenants, ratios or tests in our credit facilities, a significant portion of our indebtedness may become immediately due and payable. In addition, our lenders' commitments to make further loans to us under the Revolving Credit Facility may be suspended or terminated. We might not have, or be able to obtain, sufficient funds to make these accelerated payments. Please see Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources."

Affiliates of our general partner, including CenterPoint Energy and OGE Energy, may compete with us, and neither our general partner nor its affiliates have any obligation to present business opportunities to us.

Under our omnibus agreement, both CenterPoint Energy and OGE Energy are prohibited from, directly or indirectly, owning, operating, acquiring or investing in any business engaged in midstream operations located within the United States, other than through us. This requirement applies to both CenterPoint Energy and OGE Energy for so long as either CenterPoint Energy or OGE Energy holds any interest in our general partner or at least 20% of our common units. However, if CenterPoint Energy or OGE Energy acquires any business with midstream operations assets that have a value in excess of $50 million (or $100 million in the aggregate with such party's other acquired midstream operations assets that have not been offered to us), the acquiring party will be required to offer to us such assets for such value. If we do 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.

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As a result, under the circumstances described above, CenterPoint Energy and OGE Energy have the ability to construct or acquire assets that directly compete with our assets. Pursuant to the terms of our Partnership Agreement, the doctrine of corporate opportunity, or any analogous doctrine, does not apply to our general partner or any of its affiliates, including its executive officers and directors and CenterPoint Energy and OGE Energy. Any such person or entity that becomes aware of a potential transaction, agreement, arrangement or other matter that may be an opportunity for us will not have any duty to communicate or offer such opportunity to us. Any such person or entity will not be liable to us 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 us. This may create actual and potential conflicts of interest between us and affiliates of our general partner and result in less than favorable treatment of us and our common unitholders.

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

Effective internal controls are necessary for us to provide reliable financial reports, prevent fraud and operate successfully as a public company. If our efforts to maintain an effective system of internal controls are not successful, we are unable to maintain adequate controls over our financial processes and reporting in the future or we are unable to comply with our obligations under Section 404 of the Sarbanes-Oxley Act of 2002, our operating results could be harmed or we may fail to meet our reporting obligations. Ineffective internal controls also could cause investors to lose confidence in our reported financial information, which would likely have a negative effect on the trading price of our common units.

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

We have become increasingly dependent on the systems, networks and technology that we use to conduct almost all aspects of our business, including the operation of our gathering, processing, transportation and storage assets, the recording of commercial transactions, and the reporting of financial information. We depend on both our own systems, networks, and technology as well as the systems, networks and technology of our vendors, customers and other business partners. Any disruption of these systems, networks and technology could disrupt the operation of our 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 our critical business functions and operations, adversely affecting our reputation, and subjecting us to possible legal claims and liability. In addition, we are not fully insured against all cybersecurity risks.

As cybersecurity attacks continue to evolve, we may be required to expend significant additional resources to continue to modify or enhance our protective measures or to investigate and remediate any vulnerabilities to cybersecurity attacks. In particular, our implementation of various procedures and controls to monitor and mitigate security threats and to increase security for our personnel, information, facilities and infrastructure may result in increased capital and operating costs. To date we have not experienced any material losses relating to cybersecurity attacks; however, there can be no assurance that we 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 our financial position, results of operations and ability to make cash distributions to unitholders.

Terrorist attacks or other physical security threats could adversely affect our business.

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

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

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

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at the affected location or facility and on our financial condition, results of operations and ability to make cash distributions to unitholders.

Additionally, in order to obtain permits and renewals of permits and other approvals in the future, we 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 our 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 our financial position, results of operations and ability to make cash distributions to unitholders.

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, delay or increase our 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 NSPS, known as subpart OOOOa, 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 our 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, we 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 our gathering and processing, transmission, and storage operations remain a possibility and could result in increased compliance costs on our operations. Furthermore, if new or more stringent federal, state or local legal restrictions are adopted in areas where our 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 our services to those customers.

There is inherent risk of the incurrence of environmental costs and liabilities in our operations due to our handling of natural gas, NGLs, crude oil, and produced water, as well as air emissions related to our 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 our business activities in many ways, such as restricting the way we can handle or dispose of wastes or requiring remedial action to mitigate pollution conditions that may be caused by our 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 our properties and facilities, many of which have been used for midstream activities for a number of years, oftentimes by third parties not under our control. Private parties, including the owners of the properties through which our gathering and transportation systems pass and facilities where our 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 our pipelines could subject us to substantial liabilities arising from environmental cleanup and restoration costs, claims made by neighboring landowners and other third parties for personal injury and property damage and fines or penalties for related violations of environmental laws or regulations. We may be unable to recover these costs from insurance. Moreover, the possibility exists that stricter laws, regulations or enforcement policies could significantly increase compliance costs and the cost of any remediation that may become necessary. Further, stricter requirements could negatively impact our customers' production and operations, resulting in less demand for our services.

Increased regulation of hydraulic fracturing and waste water injection wells could result in reductions or delays in natural gas production by our customers, which could adversely affect our financial position, results of operations and ability to make cash distributions to unitholders.

Hydraulic fracturing is a common practice that is used by many of our 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

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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 (SDWA) 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 our 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 our 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 United States 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 United States 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 United States. 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 SCOOP and STACK 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. We 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 our customers, which in turn could reduce the demand for our 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 SDWA or other regulatory mechanisms.

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

Because our operations emit various types of greenhouse gases, legislation and regulations governing greenhouse gas emissions could increase our costs related to operating and maintaining our 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 GHG emissions from specified onshore and offshore oil and natural gas production sources in the United States on an annual basis, which include certain of our operations. Additional rules, such as the updates to the oil and gas NSPS requirements finalized by the EPA in May

2016 could affect our ability to obtain air permits for new or modified facilities or require our 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, we 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 us and potentially impairing our operator’s ability to economically develop our 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 United States Congress has considered adopting legislation to limit GHG emissions. A number of state and regional efforts have also emerged that are aimed at tracking and/or reducing GHG emissions by means of cap and trade programs. These programs typically

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require major sources of GHG emissions to acquire and surrender emission allowances in return for emitting those GHGs. Any such future laws and regulations imposing reporting obligations on, or limiting emissions of, GHGs could require us to incur costs to reduce emissions of GHGs. Substantial limitations on GHG emissions could also adversely affect demand for oil and natural gas. Depending on the particular program, we 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 our services and our financial position, results of operations and ability to make cash distributions to unitholders.

Increased regulatory-imposed costs may also increase the cost of consuming, and thereby reduce demand for, the products that we gather, treat and transport. 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 GHGs 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 our results of operations.

Our operations are subject to extensive regulation by federal regulatory authorities. Changes or additional regulatory measures adopted by such authorities could adversely affect our financial position, results of operations and ability to make cash distributions to unitholders.

The rates charged by several of our pipeline systems, including for interstate gas transportation service provided by our intrastate pipelines, are regulated by FERC. FERC and state regulatory agencies also regulate other terms and conditions of the services we may offer. If one of these regulatory agencies, on its own initiative or due to challenges by third parties, were to lower our tariff rates or deny any rate increase or other material changes to the types, or terms and conditions, of service we might propose or offer, the profitability of our pipeline businesses could suffer. If we were permitted to raise our 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 our profitability. Furthermore, competition from other pipeline systems may prevent us from raising our tariff rates even if regulatory agencies permit us to do so. The regulatory agencies that regulate our systems periodically implement new rules, regulations and terms and conditions of services subject to their jurisdiction. New initiatives or orders may adversely affect the rates charged for our services or otherwise adversely affect our financial position, results of operations and ability to make cash distributions to our unitholders.

Our natural gas interstate pipelines are regulated by FERC under the Natural Gas Act of 1938, or NGA, the Natural Gas Policy Act of 1978, or NGPA, and the Energy Policy Act of 2005, or EPAct of 2005. Generally, FERC's authority over interstate natural gas transportation extends to:

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

Should we fail to comply with all applicable FERC-administered statutes, rules, regulations and orders, we could be subject to substantial penalties and fines. Under the EPAct of 2005, FERC has civil penalty authority under the NGA and the NGPA to impose penalties for current violations of up to approximately $1.27 million per day for each violation and possible criminal penalties of up to approximately $1.27 million per violation.

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

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

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

Our crude oil gathering systems in the Williston Basin are subject to common carrier regulation by FERC under the Interstate Commerce Act, or ICA. The ICA requires that we maintain tariffs on file with FERC setting forth the rates we charge for providing transportation services, as well as the rules and regulations governing such services. The ICA also requires, among other things, that our rates must be "just and reasonable" and that we provide service in a manner that is nondiscriminatory. Shippers on our FERC-regulated crude oil gathering systems may protest our tariff filings, file complaints against our existing rates, or FERC can investigate our rates on its own initiative. If FERC finds that our existing or proposed rates are unjust and unreasonable, it could deny requested rate increases or could order us to reduce our 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 Tax Cuts and Jobs Act was enacted, which reduced the highest marginal United States federal corporate income tax rate from 35% to 21% for tax years beginning after December 31, 2017. In a series of related issuances on March 15, 2018, the FERC issued a Revised Policy Statement stating that it will no longer permit pipelines organized as master limited partnerships to recover an income tax allowance in their cost-of-service rates. On July 18, 2018, FERC issued a Final Rule adopting procedures that are generally the same as proposed in a March 15, 2018 NOPR implementing the Revised Policy Statement and the corporate income tax rate reduction with certain clarifications and modifications. For more information, please read Item 1, "Business-Rate and Other Regulation."

If FERC requires us to establish new tariff rates for either our natural gas or crude oil pipelines that reflect a lower federal corporate income tax rate, it is possible the rates would be reduced, which could adversely affect our financial position, results of operations and ability to make cash distributions to our unitholders.

Our 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 our financial position, results of operations and ability to make cash distributions to unitholders.

Our pipeline operations that are not regulated by FERC may be subject to state and local regulation applicable to intrastate natural 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. We cannot predict what effect, if any, such changes might have on our operations, but we 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 our business. Any such state or local regulation could have an adverse effect on our business and our financial position, results of operations and ability to make cash distributions to unitholders. For more information, please read Item 1, "Business-Rate and Other Regulation."

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

Our natural gas gathering and intrastate transportation systems are generally exempt from the jurisdiction of FERC under the NGA, and our crude oil gathering system in the Anadarko Basin is generally exempt from the jurisdiction of FERC under the ICA. Nevertheless, FERC regulation may indirectly impact these businesses and the markets for products derived from these businesses. 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, FERC has pursued pro-competitive policies in its regulation of interstate oil and natural gas pipelines. However, we cannot assure you that 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 FERC has not made a formal determination with respect to all of our facilities we consider to be engaged in natural gas gathering or a formal determination with respect to our facilities that we consider to be engaged in intrastate crude oil gathering, management believes that our natural gas gathering facilities meet the traditional tests that FERC has used to determine that a pipeline is a natural gas gathering pipeline and our intrastate crude oil gathering facilities meet the traditional tests that 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 FERC determines whether facilities are subject to regulation under the NGA or the ICA on a case-by-case basis, so the classification and regulation of our facilities is subject to change based on future determinations by FERC, the courts or Congress. If 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 FERC. Such regulation could decrease revenue, increase operating costs, and, depending upon the facility in question, could adversely affect our financial condition, results of operations and ability to make cash distributions to our unitholders. In addition, if any of our facilities were found to have provided services or otherwise operated in violation of the NGA, NGPA or ICA, 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 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 they become subject to the application of state regulation of rates and services. Our gathering operations could also be subject to safety and operational regulations relating to the design, construction, testing, operation, replacement and maintenance of gathering facilities. We cannot predict what effect, if any, such changes might have on our operations, but we could be required to incur additional capital expenditures and increased costs depending on future legislative and regulatory changes.

We 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 our pipeline operations are subject to pipeline safety laws and regulations. PHMSA regulates safety requirements for the design, construction, maintenance and operation of jurisdictional natural gas and hazardous liquids pipeline facilities. All of our interstate and intrastate natural gas transportation pipeline facilities are PHMSA jurisdictional and certain of our natural gas gathering, NGL, and crude oil pipeline facilities are PHMSA 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 us, 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 PHMSA or comparable state pipeline safety regulations could result in a number of consequences which may have an adverse effect on our operations. We incur significant costs associated with our compliance with existing PHMSA and comparable state pipeline regulations. We incurred maintenance capital expenditures and operation and maintenance expenses of $54 million in 2018 and currently estimate that we will incur maintenance capital expenditures and operation and maintenance expenses of up to $65 million in 2019 under our 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

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MAOP or MOP. We may incur significant cost associated with repair, remediation, preventive and mitigation measures associated with our integrity management programs for pipelines that are not currently subject to regulation by PHMSA.

Changes to pipeline safety regulations occur frequently. For example, PHMSA 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 PHMSA integrity management requirements (e.g., 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 us to install new or modified safety controls, pursue new capital projects, or conduct maintenance programs on an accelerated basis, all of which could require us to incur increased and potentially significant operational costs.

Financial reform regulations under the Dodd-Frank Act could adversely affect our ability to use derivative instruments to hedge risks associated with our business.

At times, we may hedge all or a portion of our commodity risk and our interest rate risk. The federal government regulates the derivatives markets and entities, including businesses like ours, that participate in those markets through the Dodd-Frank Wall Street Reform and Consumer Protection Act, or the Dodd-Frank Act, which requires the Commodity Futures Trading Commission, or the CFTC, and the SEC to promulgate rules and regulations implementing the legislation. Under the CFTC's regulations, we are subject to reporting and recordkeeping obligations for transactions involving non-financial swap transactions. The CFTC 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 CFTC published a Notice of Proposed Rulemaking designed to implement new position limits regulation and in December 2016, the CFTC re-proposal position limits regulations. The ultimate form and timing of the implementation of the regulatory regime affecting commodity derivatives remains uncertain.

The CFTC 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 us has a required identification number, is not a financial entity as defined by the regulations, and meets a minimum asset test. Management believes our hedging transactions qualify for this "commercial end-user" exception. The Dodd-Frank Act may also require us to comply with margin requirements in connection with our hedging activities, although the application of those provisions to us is uncertain at this time. The Dodd-Frank Act may also require the counterparties to our 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 our industry (including requirements to post collateral which could adversely affect our available liquidity), materially alter the terms of derivatives contracts, reduce the availability of derivatives to protect against risks we encounter, reduce our ability to monetize or restructure our existing derivatives contracts, and increase our exposure to less creditworthy counterparties, particularly if we are unable to utilize the commercial end user exception with respect to certain of our hedging transactions. If we reduce our use of hedging as a result of the legislation and regulations, our results of operations may become more volatile and our cash flows may be less predictable, which could adversely affect our 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. Our 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 our financial position, results of operations and our ability to make cash distributions to unitholders.

Risks Related to an Investment in Us

Our general partner and its affiliates, including CenterPoint Energy and OGE Energy, have conflicts of interest with us and limited duties to us and our unitholders, and they may favor their own interests to the detriment of us and our other common unitholders.

Affiliates of CenterPoint Energy and OGE Energy own and control our general partner and appoint all of the directors of our general partner. Some of the directors of our general partner are appointed to represent CenterPoint Energy or OGE Energy and are also officers and/or directors of CenterPoint Energy or OGE Energy, respectively. Although our general partner has a duty to manage us in a manner that is beneficial to us and our unitholders, the directors of our general partner who are appointed to

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represent CenterPoint Energy or OGE Energy have a fiduciary duty to perform their obligations as directors in a manner that is beneficial to CenterPoint Energy or OGE Energy, respectively. Conflicts of interest will arise between CenterPoint Energy, OGE Energy and our general partner, on the one hand, and us and our unitholders, on the other hand. In resolving these conflicts of interest, our general partner may favor its own interests and the interests of CenterPoint Energy and OGE Energy over our interests and the interests of our unitholders. These conflicts include the following situations, among others:

- Neither the Partnership Agreement nor any other agreement requires CenterPoint Energy or OGE Energy to pursue a business strategy that favors us. The directors and officers of CenterPoint Energy and OGE Energy have a fiduciary duty to make decisions in the best interests of the stockholders of their respective companies, which may be contrary to our interests. CenterPoint Energy and OGE Energy may choose to shift the focus of their investment and growth to areas not served by our assets. In addition, CenterPoint Energy is the holder of our Series A Preferred Units and may favor its interests in voting in favor of actions relating to such units, including voting in favor of making distributions on such Series A Preferred Units even if no distributions are made on the common units.
- Our general partner is allowed to take into account the interests of parties other than us, such as CenterPoint Energy and OGE Energy, in resolving conflicts of interest.
- Some of the directors of our general partner are also officers and/or directors of CenterPoint Energy or OGE Energy and will owe fiduciary duties to their respective companies. These individuals may also devote significant time to the business of CenterPoint Energy or OGE Energy, respectively.
- The Partnership Agreement replaces the fiduciary duties that would otherwise be owed to us by our general partner with contractual standards governing its duties, limits our general partner’s liabilities and restricts the remedies available to our unitholders for actions that, without such limitations, might constitute breaches of fiduciary duty.
- Except in limited circumstances, our general partner has the power and authority to conduct our business without unitholder approval.
- Disputes may arise under our commercial agreements with CenterPoint Energy and OGE Energy.
- Our general partner determines the amount and timing of asset purchases and sales, borrowings, issuances of additional partnership units and the creation, reduction or increase of cash reserves, each of which can affect the amount of distributable cash flow.
- Our general partner determines the amount and timing of any capital expenditures and whether a capital expenditure is classified as a maintenance capital expenditure, which reduces operating surplus, or an expansion or investment capital expenditure, which does not reduce operating surplus. This determination can affect the amount of cash that is distributed to our unitholders.
- Our general partner determines which costs incurred by it and its affiliates are reimbursable by us.
- Our general partner may cause us to borrow funds in order to permit the payment of cash distributions, even if the purpose or effect of the borrowing is to make incentive distributions.
- The Partnership Agreement permits us to classify up to $300 million as operating surplus, even if it is generated from asset sales, non-working capital borrowings or other sources that would otherwise constitute capital surplus. This cash may be used to fund distributions to our general partner in respect of the incentive distribution rights.
- The Partnership Agreement does not prohibit our general partner from causing us to pay it or its affiliates for any services rendered to us or entering into additional contractual arrangements with any of these entities on our behalf.
- Our general partner intends to limit its liability regarding our contractual and other obligations.
- Our general partner may exercise its right to call and purchase all of the common units not owned by it and its affiliates if they own more than 90% of the common units. If our general partner and its affiliates reduce their ownership percentage to below 70% of the outstanding units, the ownership threshold to exercise the call right will be permanently reduced to 80%.
- Our general partner controls the enforcement of the obligations that it and its affiliates owe to us.
- Our general partner decides whether to retain separate counsel, accountants or others to perform services for us.
- Our general partner may transfer its incentive distribution rights without unitholder approval.
- Our general partner may elect to cause us to issue common units to it in connection with a resetting of the target distribution levels related to our general partner’s incentive distribution rights without the approval of the conflicts

committee of the Board of Directors or our unitholders. This election may result in lower distributions to our common unitholders in certain situations.

If a unitholder is not an Eligible Holder, the unitholder’s common units may be subject to redemption.

Our Partnership Agreement includes certain requirements regarding those investors who may own our common and preferred units. Eligible Holders are limited partners whose (i) federal income tax status is not reasonably likely to have a material adverse effect on the rates that can be charged by us on assets that are subject to regulation by FERC or an analogous regulatory body and (ii) nationality, citizenship or other related status would not create a substantial risk of cancellation or forfeiture of any property in which we have an interest, in each case as determined by our general partner with the advice of counsel. If the unitholder is not an Eligible Holder, in certain circumstances as set forth in our Partnership Agreement, the unitholder’s units may be redeemed by us at the then-current market price. The redemption price will be paid in cash or by delivery of a promissory note, as determined by our general partner.

Our Partnership Agreement requires that we distribute all of our available cash, which could limit our ability to grow and make acquisitions.

Our Partnership Agreement requires that we distribute all of our available cash to our unitholders and will rely primarily upon external financing sources, including commercial borrowings and the issuance of debt and equity securities, to fund our acquisitions and expansion capital expenditures. As a result, to the extent we are unable to finance growth externally, our cash distribution policy will significantly impair our ability to grow. For further information related to distributions of available cash, please see Item 7. “Management’s Discussion and Analysis of Financial Condition and Results of Operations.”

In addition, because we are required to distribute all of our available cash, our growth may not be as fast as that of businesses that reinvest their available cash to expand ongoing operations. To the extent we issue additional units in connection with any acquisitions or expansion capital expenditures, the payment of distributions on those additional units may increase the risk that we will be unable to maintain or increase our per unit distribution level. There are no limitations in our Partnership Agreement or in our credit facility that limit our ability to issue additional units, including units ranking senior to the common units. The incurrence of additional commercial borrowings or other debt to finance our growth strategy would result in increased interest expense, which in turn may impact the available cash that we have to distribute to our unitholders.

Any reductions in our credit ratings could increase our financing costs and the cost of maintaining certain contractual relationships.

We cannot assure you that our 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 our credit ratings are below investment grade, we may have higher future borrowing costs and we or our 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 we were experiencing significant working capital requirements or otherwise lacked liquidity, our financial position, results of operations and ability to make cash distributions to unitholders could be adversely affected.

The credit and business risk profiles and the business plans of our sponsors could adversely affect our credit ratings and profile.

The credit and business risk profiles and the business plans of our sponsors may be factors in credit evaluations of us because, through their indirect ownership of our general partner, they can influence our business activities, including our cash distribution strategy, acquisition strategy, and business risk profile. The financial conditions of CenterPoint Energy and OGE Energy, including the degree of their financial leverage and their dependence on cash flows from us, as well as their business plans with respect to their investment in us, may be considered by credit rating agencies in their assessment of our credit ratings and profile.

CenterPoint Energy and OGE Energy, which indirectly own our general partner, have indebtedness outstanding and are partially dependent on the cash distributions from their general partner and limited partner interests in us to service such indebtedness and pay dividends on their common stock. Any distributions by us to such entities will be made only after satisfying our then-current obligations to our creditors. Our credit ratings and business risk profile could be adversely affected if the ratings and risk profiles of the entities that control our general partner were viewed as substantially lower or riskier than ours.

Our Partnership Agreement replaces our general partner’s fiduciary duties to holders of our common units with contractual standards governing its duties.

Our Partnership Agreement contains provisions that eliminate the fiduciary standards to which our general partner would otherwise be held by state fiduciary duty law and replaces those duties with several different contractual standards. For example, our Partnership Agreement permits our general partner to make a number of decisions in its individual capacity, as opposed to in its capacity as our general partner, free of any duties to us and our unitholders other than the implied contractual covenant of good

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faith and fair dealing, which means that a court will enforce the reasonable expectations of the partners where the language in the Partnership Agreement does not provide for a clear course of action. This provision entitles our general partner to consider only the interests and factors that it desires and relieves it of any duty or obligation to give any consideration to any interest of, or factors affecting, us, our affiliates or our limited partners. Examples of decisions that our general partner may make in its individual capacity include:

- how to allocate corporate opportunities among us and its other affiliates;
- whether to exercise its limited call right;
- whether to seek approval of the resolution of a conflict of interest by the conflicts committee of the Board of Directors;
- whether to elect to reset target distribution levels;
- whether to transfer the incentive distribution rights to a third party; and
- whether or not to consent to any merger or consolidation of the Partnership or amendment to the Partnership Agreement.

By purchasing a common unit, a common unitholder agrees to become bound by the provisions in the Partnership Agreement, including the provisions discussed above.

Our Partnership Agreement restricts the remedies available to holders of our common units for actions taken by our general partner that might otherwise constitute breaches of fiduciary duty.

Our Partnership Agreement contains provisions that restrict the remedies available to unitholders for actions taken by our general partner that might otherwise constitute breaches of fiduciary duty under state fiduciary duty law. For example, our Partnership Agreement provides that:

- whenever our general partner, the Board of Directors or any committee thereof (including the conflicts committee) makes a determination or takes, or declines to take, any other action in their respective capacities, our general partner, the Board of Directors and any committee thereof (including the conflicts committee), as applicable, is required to make such determination, or take or decline to take such other action, in good faith, meaning that it subjectively believed that the decision was in the best interests of the Partnership, and, except as specifically provided by our Partnership Agreement, will not be subject to any other or different standard imposed by our Partnership Agreement, Delaware law, or any other law, rule or regulation, or at equity;
- our general partner will not have any liability to us or our unitholders for decisions made in its capacity as a general partner so long as such decisions are made in good faith;
- our general partner and its officers and directors will not be liable for monetary damages to us or our limited partners resulting from any act or omission unless there has been a final and non-appealable judgment entered by a court of competent jurisdiction determining that our general partner or its officers and directors, as the case may be, acted in bad faith or engaged in fraud or willful misconduct or, in the case of a criminal matter, acted with knowledge that the conduct was criminal; and
- our general partner will not be in breach of its obligations under the Partnership Agreement (including any duties to us or our unitholders) if a transaction with an affiliate or the resolution of a conflict of interest is:
- approved by the conflicts committee of the Board of Directors, although our general partner is not obligated to seek such approval;
- approved by the vote of a majority of the outstanding common units, excluding any common units owned by our general partner and its affiliates;
- determined by the Board of Directors to be on terms no less favorable to us than those generally being provided to or available from unrelated third parties; or
- determined by the Board of Directors to be fair and reasonable to us, taking into account the totality of the relationships among the parties involved, including other transactions that may be particularly favorable or advantageous to us.

In connection with a situation involving a transaction with an affiliate or a conflict of interest, any determination by our general partner or the conflicts committee must be made in good faith. If an affiliate transaction or the resolution of a conflict of interest is not approved by our common unitholders or the conflicts committee and the Board of Directors determines that the resolution or course of action taken with respect to the affiliate transaction or conflict of interest satisfies either of the standards set forth in the third and fourth sub-bullets above, then it will be presumed that, in making its decision, the Board of Directors

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acted in good faith, and in any proceeding brought by or on behalf of any limited partner or the Partnership challenging such determination, the person bringing or prosecuting such proceeding will have the burden of overcoming such presumption.

Our general partner may elect to cause us to issue common units to it in connection with a resetting of the minimum quarterly distribution and the target distribution levels related to our general partner's incentive distribution rights without the approval of the conflicts committee of our general partner or our unitholders. This may result in lower distributions to our common unitholders in certain situations.

Our general partner has the right, if it has received incentive distributions at the highest level to which it is entitled (50%) for each of the prior four consecutive fiscal quarters and the amount of each such distribution did not exceed the adjusted operating surplus for such quarter, respectively, to reset the initial minimum quarterly distribution and cash target distribution levels at higher levels based on the average cash distribution amount per common unit for the two fiscal quarters prior to the exercise of the reset election. Following a reset election by our general partner, the minimum quarterly distribution amount will be reset to an amount equal to the average cash distribution amount per common unit for the two fiscal quarters immediately preceding the reset election (such amount is referred to as the reset minimum quarterly distribution) and the target distribution levels will be reset to correspondingly higher levels based on percentage increases above the reset minimum quarterly distribution amount.

We anticipate that our general partner would exercise this reset right in order to facilitate acquisitions or internal growth projects that would not be sufficiently accretive to cash distributions per common unit without such conversion; however, it is possible that our general partner could exercise this reset election at a time when we are experiencing declines in our aggregate cash distributions or at a time when our general partner expects that we will experience declines in our aggregate cash distributions in the foreseeable future. In such situations, our general partner may be experiencing, or may be expected to experience, declines in the cash distributions it receives related to its incentive distribution rights and may therefore desire to be issued our common units, which are entitled to specified priorities with respect to our distributions and which therefore may be more advantageous for the general partner to own in lieu of the right to receive incentive distribution payments based on target distribution levels that are less certain to be achieved in the then-current business environment. This risk could be elevated if our incentive distribution rights have been transferred to a third party. Our general partner has the right to transfer the incentive distribution rights at any time, in whole or in part, and any transferee holding a majority of the incentive distribution rights shall have the same rights as our general partner with respect to resetting target distributions. As a result, a reset election may cause our common unitholders to experience dilution in the amount of cash distributions that they would have otherwise received had we not issued new common units to our general partner in connection with resetting the target distribution levels related to our general partner incentive distribution rights.

Holders of our common units have limited voting rights and are not entitled to elect our general partner or its directors.

Unlike the holders of common stock in a corporation, unitholders have only limited voting rights on matters affecting our business and, therefore, limited ability to influence management's decisions regarding our business. Unitholders have no right to elect our general partner or its Board of Directors on an annual or other continuing basis. Because CenterPoint Energy and OGE Energy collectively indirectly own 100% of our general partner, the Board of Directors has been, and, as long as CenterPoint Energy and OGE Energy own 100% of our general partner, will continue to be, chosen by CenterPoint Energy and OGE Energy. Furthermore, if the unitholders were dissatisfied with the performance of our general partner, they will have little ability to remove our general partner. Please see "—Even if holders of our common units are dissatisfied, they will not be able to remove our general partner without its consent." As a result of these limitations, the price at which the common units will trade could be diminished because of the absence or reduction of a takeover premium in the trading price. Our Partnership Agreement also contains provisions limiting the ability of unitholders to call meetings or to acquire information about our operations, as well as other provisions limiting the unitholders' ability to influence the manner or direction of management.

Even if holders of our common units are dissatisfied, they will not be able to remove our general partner without its consent.

The unitholders are unable to remove our general partner without its consent because affiliates of our general partner own sufficient units to be able to prevent its removal. The vote of the holders of at least 75% of all outstanding units voting together as a single class is required to remove our general partner. As of February 1, 2019, affiliates of our general partner owned 79.6% of our aggregate outstanding common units.

Our Partnership Agreement restricts the voting rights of unitholders owning 20% or more of our common units.

Unitholders' voting rights are further restricted by a provision of our Partnership Agreement providing that any units held by a person that owns 20% or more of any class of units then outstanding, other than our general partner, its affiliates, their transferees and persons who acquired such units with the prior approval of the Board of Directors, cannot vote on any matter.

Our general partner's interest in us and control of our general partner may be transferred to a third party without unitholder consent.

Our general partner may transfer its general partner interest to a third party in a merger or in a sale of all or substantially all of its assets without the consent of our unitholders. Our Partnership Agreement does not restrict the ability of the owners of our general partner from transferring all or a portion of their respective limited liability company interest in our general partner to a third party. The new owners of our general partner would then be in a position to replace the Board of Directors and officers of our general partner with its own choices and thereby influence the decisions taken by the Board of Directors and officers.

The incentive distribution rights of our general partner may be transferred to a third party without unitholder consent.

Our general partner may transfer its incentive distribution rights to a third party at any time without the consent of our unitholders. If our general partner transfers its incentive distribution rights to a third party but retains its general partner interest, our general partner may not have the same incentive to grow the Partnership and increase quarterly distributions to unitholders over time as it would if it had retained ownership of its incentive distribution rights.

We may issue additional units without your approval, which would dilute your existing ownership interests.

The Partnership Agreement does not limit the number of additional limited partner interests, including limited partner interests that rank senior to the common units, that we may issue at any time without the approval of our unitholders. The issuance by us of additional common units or other equity securities of equal or senior rank will have the following effects:

- our existing unitholders' proportionate ownership interest in us 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, our 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 our common units. In addition, these sales, or the possibility that these sales may occur, could make it more difficult for us to sell our common units in the future.

Affiliates of our 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 our general partner, which may impact our strategic direction.

As of February 1, 2019, CenterPoint Energy held 233,856,623 common units and 14,520,000 Series A Preferred Units, and OGE Energy held 110,982,805 common units. Our 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 our common units held by CenterPoint Energy and OGE Energy, as well as our Series A Preferred Units held by

CenterPoint Energy, are subject to certain registration rights. In addition, in the first quarter of 2016, CenterPoint Energy announced that it was evaluating strategic alternatives for its investment in Enable. In the first quarter of 2018, CenterPoint Energy disclosed that it had decided not to pursue a sale or spin-off qualifying under Section 355 of the U.S. Internal Revenue Code at that time and that, while a transaction for all of its interests in the Partnership was not viable at that time, it may pursue such a transaction if it becomes viable in the future. CenterPoint Energy also disclosed that it may reduce its investment in the Partnership through a sale of all or a portion of the Partnership 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 Energy’s disclosure, as well as any sales by CenterPoint Energy of the common units it holds in the public equity markets, could have an adverse impact on the market for our common units, including our ability to issue equity on favorable terms to fund our capital needs or at all. Any sale of our general partner by CenterPoint Energy or OGE Energy may impact our strategic direction, business or results of operations.

Our general partner has a limited call right that may require our unitholders to sell their units at an undesirable time or price.

If at any time our general partner and its affiliates own more than 90% of our common units, our general partner will have the right, which it may assign to any of its affiliates or to us, but not the obligation, to acquire all, but not less than all, of the common units held by unaffiliated persons at a price not less than their then-current market price, as calculated pursuant to the terms of the Partnership Agreement. If our general partner and its affiliates reduce their ownership percentage to below 70% of the outstanding units, the ownership threshold to exercise the call right will be permanently reduced to 80%. As a result, our unitholders may be required to sell their common units at an undesirable time or price and may not receive any positive return on their investment. Our unitholders may also incur a tax liability upon any such sale of their units. As of February 1, 2019, affiliates of our general partner owned approximately 79.6% of our outstanding common units. If we assume the conversion of our Series A Preferred Units using the closing price of our units as of February 1, 2019, affiliates of our general partner will then own 80.7% of our aggregate outstanding common units. Affiliates of our general partner may acquire additional common units from us in connection with future transactions or through open-market or negotiated purchases.

Our unitholders' liability may not be limited if a court finds that unitholder action constitutes control of our business.

A general partner of a partnership generally has unlimited liability for the obligations of the partnership, except for those contractual obligations of the partnership that are expressly made without recourse to the general partner. The Partnership is organized under Delaware law, and we conduct business in a number of other states. The limitations on the liability of holders of limited partner interests for the obligations of a limited partnership have not been clearly established in some of the other states in which we may do business. Our unitholders could be held liable for any and all of our obligations as if they were general partners if a court or government agency were to determine that:

- we were conducting business in a state but had not complied with that particular state's partnership statute; or
- a unitholder's right to act with other unitholders to remove or replace our general partner, to approve some amendments to our Partnership Agreement or to take other actions under our Partnership Agreement constitutes "control" of our business.

Our Partnership Agreement designates the Court of Chancery of the State of Delaware as the exclusive forum for certain types of actions and proceedings that may be initiated by our unitholders, which limits our unitholders' ability to choose the judicial forum for disputes with us or our general partner's directors, officers or other employees.

Our Partnership Agreement provides, that, with certain limited exceptions, the Court of Chancery of the State of Delaware is the exclusive forum for any claims, suits, actions or proceedings (1) arising out of or relating in any way to our Partnership Agreement (including any claims, suits or actions to interpret, apply or enforce the provisions of our Partnership Agreement or the duties, obligations or liabilities among our partners, or obligations or liabilities of our partners to us, or the rights or powers of, or restrictions on, our partners or us), (2) brought in a derivative manner on our behalf, (3) asserting a claim of breach of a duty (including a fiduciary duty) owed by any of our, or our general partner's, directors, officers, or other employees, or owed by our general partner, to us or our partners, (4) asserting a claim against us arising pursuant to any provision of the Delaware Revised Uniform Limited Partnership Act or (5) asserting a claim against us governed by the internal affairs doctrine. Any person or entity purchasing or otherwise acquiring any interest in our common units is deemed to have received notice of and consented to the foregoing provisions. Although management believes this choice of forum provision benefits us by providing increased consistency in the application of Delaware law in the types of lawsuits to which it applies, the provision may have the effect of discouraging lawsuits against us and our general partner's directors and officers. The enforceability of similar choice of forum provisions in other companies' certificates of incorporation or similar governing documents has been challenged in legal proceedings and it is possible that in connection with any action a court could find the choice of forum provisions contained in our Partnership Agreement to be inapplicable or unenforceable in such action. If a court were to find this choice of forum provision inapplicable to, or unenforceable in respect of, one or more of the specified types of actions or proceedings, we may incur additional costs associated with resolving such matters in other jurisdictions, which could adversely affect our financial position, results of operations and ability to make cash distributions to our unitholders.

The NYSE does not require a publicly traded limited partnership like us to comply with certain of its corporate governance requirements.

Our common units are listed on the NYSE. Because we are a publicly traded limited partnership, the NYSE does not require us to have, and we do not intend to have, a majority of independent directors on our Board of Directors, to establish a nominating and corporate governance committee, or to have a compensation committee composed entirely of independent directors.

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Accordingly, unitholders will not have the same protections afforded to certain corporations that are subject to all of the NYSE corporate governance requirements.

Unitholders may have liability to repay distributions that were wrongfully distributed to them.

Under certain circumstances, unitholders may have to repay amounts wrongfully returned or distributed to them. Under Section 17-607 of the Delaware Revised Uniform Limited Partnership Act, we may not make a distribution to our unitholders if the distribution would cause our liabilities to exceed the fair value of our assets. Delaware law provides that for a period of three years from the date of the impermissible distribution, limited partners who received the distribution and who knew at the time of the distribution that it violated Delaware law will be liable to the limited partnership for the distribution amount. Transferees of common units are liable for both the obligations of the transferor to make contributions to the Partnership that are known to the transferee at the time of transfer and for unknown obligations if the liabilities could have been determined from the Partnership Agreement. Neither liabilities to partners on account of their partnership interest nor liabilities that are non-recourse to the Partnership are counted for purposes of determining whether a distribution is permitted.

Our general partner intends to limit its liability regarding our obligations.

Our general partner intends to limit its liability under contractual arrangements so that the counterparties to such arrangements have recourse only against our assets and not against our general partner or its assets. Our general partner may therefore cause us to incur indebtedness or other obligations that are non-recourse to our general partner. Our Partnership Agreement permits our general partner to limit its liability, even if we could have obtained more favorable terms without the limitation on liability. In addition, we are obligated to reimburse or indemnify our general partner to the extent that it incurs obligations on our behalf. Any such reimbursement or indemnification payments would reduce the amount of cash otherwise available for distribution to our unitholders.

An increase in interest rates could adversely impact the price of our common units, our ability to issue equity or incur debt for acquisitions or other purposes and our ability to make cash distributions at our intended levels.

Interest rates on future credit facilities and debt offerings could be higher than current levels, causing our financing costs to increase accordingly. As with other yield-oriented securities, the market price of our common units is impacted by the level of our cash distributions and implied distribution yield. The distribution yield is often used by investors to compare and rank related yield-oriented securities for investment decision purposes. Therefore, changes in interest rates may affect the yield requirements of investors who invest in our units, and a rising interest rate environment could have an adverse impact on the price of our common units, our ability to issue additional equity to make acquisitions or for other purposes, our financial position, results of operations and our ability to make cash distributions at our intended levels.

Our Series A Preferred Units have rights, preferences and privileges that are not held by, and are preferential to the rights of, holders of our common units.

Our Series A Preferred Units rank senior to all of our other classes or series of equity securities with respect to distribution rights and rights upon liquidation. We cannot declare or pay a distribution to our 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 market price for our common units or could make it more difficult for us to sell our 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 our general partner, a quarterly cash distribution, subject to certain adjustments, equal to an annual rate of 10% 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 LIBOR plus a spread of 850 bps 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 our 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. Our Series A Preferred Units are convertible into common units by the holders of such units in certain circumstances. Payment of distributions on our Series A Preferred Units, or on the common units issued following the conversion of such Series A Preferred Units, could impact our liquidity and reduce the amount of cash flow available for working capital, capital expenditures, growth opportunities, acquisitions, and other general partnership purposes. Our obligations to the holders of Series A Preferred Units could also limit our ability to obtain additional financing or increase our borrowing costs, which could have an adverse effect on our financial condition.

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Our Series A Preferred Units contain covenants that may limit our business flexibility.

Our Series A Preferred Units contain covenants preventing us from taking certain actions without the approval of the holders of 66 2⁄3% 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 our ability to take certain actions that management or our board of directors may consider to be in the best interests of our unitholders. The affirmative vote of 66 2⁄3% of the outstanding Series A Preferred Units, voting as a single class, is necessary to amend the 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% 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 million or create or issue any senior securities or (B) subject to our right to redeem the Series A Preferred Units, approve certain fundamental transactions.

Our Series A Preferred Units are required to be redeemed in certain circumstances if they are not eligible for trading on the NYSE, and we may not have sufficient funds to redeem our Series A Preferred Units if we are required to do so.

The holders of our Series A Preferred Units may request that we list those units for trading on the NYSE. If we are unable to list the Series A Preferred Units in certain circumstances, we will be required to redeem the Series A Preferred Units. There can be no assurance that we would have sufficient financial resources available to satisfy our obligation to redeem the Series A Preferred Units. In addition, mandatory redemption of our Series A Preferred Units could adversely affect our financial position, results of operations and ability to make cash distributions to unitholders.

Tax Risks to Common Unitholders

Our tax treatment depends on our status as a partnership for federal income tax purposes. If the IRS were to treat us as a corporation for federal income tax purposes, which would subject us to entity-level taxation, then our distributable cash flow to our unitholders would be substantially reduced.

The anticipated after-tax economic benefit of an investment in the common units depends largely on our being treated as a partnership for federal income tax purposes. We have not requested a ruling from the Internal Revenue Service, or IRS, regarding our qualification as a partnership for tax purposes.

Despite the fact that we are a limited partnership under Delaware law, it is possible in certain circumstances for a partnership such as ours to be treated as a corporation for federal income tax purposes. A change in our business or a change in current law could cause us to be treated as a corporation for federal income tax purposes or otherwise subject us to taxation as an entity.

If we were treated as a corporation for federal income tax purposes, we would pay federal income tax on our taxable income at the corporate tax rate, which changed from 35% to 21% for tax years beginning after December 31, 2017 and would likely pay state and local income tax at varying rates. Distributions to our unitholders would generally be taxed again as corporate dividends (to the extent of our current and accumulated earnings and profits), and no income, gains, losses, deductions, or credits would flow through to such unitholders. Because a tax would be imposed upon us as a corporation, our distributable cash flow to our unitholders would be substantially reduced. Therefore, if we were treated as a corporation for federal income tax purposes there would be material reductions in the anticipated cash flow and after-tax return to our unitholders, likely causing a substantial reduction in the value of our common units.

This could adversely affect our financial position, results of operations and ability to make cash distributions to unitholders.

Our Partnership Agreement provides that, if a law is enacted or existing law is modified or interpreted in a manner that subjects us to taxation as a corporation or otherwise subjects us to entity-level taxation for federal, state or local income tax purposes, the minimum quarterly distribution amount and the target distribution amounts may be adjusted to reflect the impact of that law on us.

If we were subjected to a material amount of additional entity-level taxation by individual states, it would reduce our distributable cash flow to our unitholders.

Changes in current state law may subject us to additional entity-level taxation by individual states. Because of widespread state budget deficits and other reasons, several states are evaluating ways to subject partnerships to entity-level taxation through the imposition of state income, franchise and other forms of taxation. Imposition of such additional tax on us by a state will reduce

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the distributable cash flow. Our Partnership Agreement provides that, if a law is enacted or an existing law is modified or interpreted in a manner that subjects us to entity-level taxation, the minimum quarterly distribution amount and the target distribution amounts may be adjusted to reflect the impact of that law on us.

The tax treatment of publicly traded partnerships or an investment in our common units could be subject to potential legislative, judicial or administrative changes and differing interpretations of applicable law, possibly on a retroactive basis.

The present federal income tax treatment of publicly traded partnerships, including us, or an investment in our common units may be modified by administrative, legislative or judicial interpretation at any time. From time to time, members of the U.S. Congress propose and consider substantive changes to the existing federal income tax laws that affect publicly traded partnerships. Although there is no current legislative proposal, a prior legislative proposal would have eliminated the qualifying income exception to the treatment of all publicly-traded partnerships as corporations upon which we rely for our treatment as a partnership for federal income tax purposes.

Any modification to the federal income tax laws and interpretations thereof could make it more difficult or impossible to meet the exception for us to be treated as a partnership for U.S. federal income tax purposes. We are unable to predict whether any such changes will ultimately be enacted, but it is possible that a change in law could affect us and may, if enacted, be applied retroactively. Any such changes could negatively impact the value of an investment in our common units. You are urged to consult with your own tax advisor with respect to the status of regulatory or administrative developments and proposals and their potential effect of your investment in our common units.

Our unitholders are required to pay income taxes on their share of our taxable income even if they do not receive any cash distributions from us. A unitholder’s share of our taxable income, and its relationship to any distributions we make, may be affected by a variety of factors, including our economic performance, transactions in which we engage or changes in law and may be substantially different from any estimate we make in connection with a unit offering.

A unitholder’s allocable share of our taxable income will be taxable to the unitholder, which may require the unitholder to pay federal income taxes and, in some cases, state and local income taxes, even if the unitholder receives cash distributions from us that are less than the actual tax liability that results from that income or no cash distributions at all.

A unitholder’s share of our taxable income, and its relationship to any distributions we make, may be affected by a variety of factors, including our economic performance, which may be affected by numerous business, economic, regulatory, legislative, competitive and political uncertainties beyond our control, and certain transactions in which we might engage. For example, we may engage in transactions that produce substantial taxable income allocations to some or all of our unitholders without a corresponding increase in cash distributions to our unitholders, such as a sale or exchange of assets, the proceeds of which are reinvested in our business or used to reduce our debt, or an actual or deemed satisfaction of our indebtedness for an amount less than the adjusted issue price of the debt. The ratio of a unitholder’s share of taxable income to the cash received by it may also be affected by changes in law. For instance, under the Tax Cuts and Jobs Act, for taxable years beginning after 2017 the net interest expense deductions of certain business entities, including us, are limited to 30% of such entity’s “adjusted taxable income,” which is generally taxable income with certain modifications. If the limit applies, a unitholder’s taxable income allocations will be more (or its net loss allocations will be less) than would have been the case absent the limitation.

From time to time, in connection with an offering of our units, we may state an estimate of the ratio of federal taxable income to cash distributions that a purchaser of units in that offering may receive in a given period. These estimates depend in part on factors that are unique to the offering with respect to which the estimate is stated, so the expected ratio applicable to other units will be different, and in many cases less favorable, than these estimates. Moreover, even in the case of units purchased in the offering to which the estimate relates, the estimate may be incorrect, due to the uncertainties described above, challenges by the IRS to tax reporting positions which we adopt, or other factors. The actual ratio of taxable income to cash distributions could be higher or lower than expected, and any differences could be material and could materially affect the value of the common units.

If the IRS contests the federal income tax positions we take, the market for our common units may be adversely impacted and the cost of any IRS contest would likely reduce our distributable cash flow to unitholders.

We have not requested a ruling from the IRS with respect to our treatment as a partnership for federal income tax purposes. The IRS may adopt positions that differ from the conclusions of our counsel expressed in a prospectus or from the positions we take, and the IRS's positions may ultimately be sustained. It may be necessary to resort to administrative or court proceedings to sustain some or all of our counsel's conclusions or the positions we take and such positions may not ultimately be sustained. A court may not agree with some or all of our counsel's conclusions or the positions we take. Any contest with the IRS, and the outcome of any IRS contest, may have a materially adverse effect on the market for our common units and the price at which they

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trade. In addition, our costs of any contest with the IRS would be borne indirectly by our unitholders and our general partner because the costs would likely reduce our distributable cash flow to our unitholders.

If the IRS makes audit adjustments to our income tax returns for tax years beginning after 2017, the IRS (and some states) may collect any resulting taxes (including any applicable penalties and interest) directly from us, in which case we may require our unitholders and former unitholders to reimburse us for such taxes (including any applicable penalties or interest) or, if we are required to bear such payment, our cash available for distribution to our unitholders might be substantially reduced.

Pursuant to the Bipartisan Budget Act of 2015, if the IRS makes audit adjustments to our income tax returns for tax years beginning after 2017, it may collect any resulting taxes (including any applicable penalties and interest) directly from us. We will generally have the ability to shift any such tax liability to our general partner and our unitholders in accordance with their interests in us during the year under audit, but there can be no assurance that such election will be practical, permissible or effective under all circumstances, or that we will be able to (or choose to) effect corresponding shifts in state income or similar tax liability resulting from the IRS adjustment in states in which we do business in the year under audit or in the adjustment year. If we make payments of taxes, penalties and interest resulting from audit adjustments, we may require our unitholders and former unitholders to reimburse us for such taxes (including any applicable penalties or interest) or, if we are required to bear such payment, our cash available for distribution to our unitholders might be substantially reduced. In addition, because payment would be due during the year in which the audit is completed, unitholders during that year would bear the burden of the adjustment even if they were not unitholders during the audited taxable year.

In the event the IRS makes an audit adjustment to our income tax returns and we do not or cannot shift the liability to our unitholders in accordance with their interests in us during the year under audit, we will generally have the ability to request that the IRS reduce the determined underpayment by the amount of any suspended passive loss carryovers of specified unitholders (without any compensation from us to such unitholders). Such reduction, if approved by the IRS, will be binding on any affected unitholders.

Tax gain or loss on the disposition of our common units could be more or less than expected.

If any of our unitholders sells their common units, such unitholders must recognize a gain or loss for federal income tax purposes equal to the difference between the amount realized and such unitholder’s tax basis in those common units. Because distributions in excess of such unitholder’s allocable share of our net taxable income decrease such unitholder’s tax basis in such unitholder’s common units, the amount, if any, of such prior excess distributions with respect to the common units such unitholder sells will, in effect, become taxable income if such unitholder sells such common units at a price greater than its tax basis in those common units, even if the price such unitholder receives is less than its original cost. Furthermore, a substantial portion of the amount realized on any sale or other disposition of such unitholder’s common units, whether or not representing gain, may be taxed as ordinary income due to potential recapture items, including depreciation recapture. In addition, because the amount realized includes a unitholder’s share of our nonrecourse liabilities, if a unitholder sells its common units, it may incur a tax liability in excess of the amount of cash it receives from the sale. Thus, a unitholder may recognize both ordinary income and capital loss from the sale of units if the amount realized on a sale of such units is less than the unitholder's adjusted basis in the units. Net capital loss may only offset capital gains and, in the case of individuals, up to $3,000 of ordinary income per year. In the taxable period in which a unitholder sells its common units, such unitholder may recognize ordinary income from our allocations of income and gain to such unitholder prior to the sale and from recapture items that generally cannot be offset by any capital loss recognized upon the sale of units.

Tax-exempt entities and non-U.S. persons face unique tax issues from owning our common units that may result in adverse tax consequences to them.

Investment in our common units by tax-exempt entities, such as employee benefit plans and individual retirement accounts (known as IRAs), and non-U.S. persons raises issues unique to them. For example, virtually all of our income allocated to organizations that are exempt from federal income tax, including IRAs and other retirement plans, will be unrelated business taxable income (UBTI) and will be taxable to the exempt organization as UBTI on the exempt organization’s tax return in the year the exempt organization is allocated the income. Further, with respect to taxable years beginning after December 31, 2017, a tax-exempt entity with more than one unrelated trade or business (including by attribution from investment in a partnership such as ours) is required to compute the UBTI of such tax-exempt entity separately with respect to each trade or business (including for purposes of determining any net operating loss deduction). As a result, for years beginning after December 31, 2017, it may not be possible for tax-exempt entities to utilize losses from an investment in our partnership to offset unrelated business taxable income from another unrelated trade or business and vice versa. Tax-exempt entities should consult a tax advisor before investing in our common units.

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Distributions to non-U.S. persons will be reduced by withholding taxes at the highest applicable effective tax rate, and non-U.S. persons will be required to file U.S. federal income tax returns and pay tax on their share of our taxable income.

Under the Tax Cuts and Jobs Act, if a unitholder sells or otherwise disposes of a common unit, the transferee is required to withhold 10.0% of the amount realized by the transferor unless the transferor certifies that it is not a foreign person, and we are required to deduct and withhold from the transferee amounts that should have been withheld by the transferee but were not withheld. However, the Department of the Treasury and the IRS have determined that this withholding requirement should not apply to any disposition of a publicly traded interest in a publicly traded partnership (such as us) until regulations or other guidance have been issued clarifying the application of this withholding requirement to dispositions of interests in publicly traded partnerships. Accordingly, while this new withholding requirement does not currently apply to interests in us, there can be no assurance that such requirement will not apply in the future.

If you are a tax-exempt entity or a non-U.S. person, you should consult a tax advisor before investing in our common units.

We treat each holder of our common units as having the same tax benefits without regard to the actual common units held. The IRS may challenge this treatment, which could adversely affect the value of the common units.

Because we cannot match transferors and transferees of common units and because of other reasons, we have adopted depreciation and amortization positions that may not conform to all aspects of existing Treasury Regulations. A successful IRS challenge to those positions could adversely affect the amount of tax benefits available to our unitholders. A successful IRS challenge also could affect the timing of these tax benefits or the amount of gain from a unitholder's sale of common units and could have a negative impact on the value of our common units or result in audit adjustments to such unitholder's tax returns.

We generally prorate our items of income, gain, loss and deduction for U.S. federal income tax purposes between transferors and transferees of our units each month based upon the ownership of our units on the first day of each month, instead of on the basis of the date a particular unit is transferred. The IRS may challenge this treatment, which could change the allocation of items of income, gain, loss and deduction among our unitholders.

We generally prorate our items of income, gain, loss and deduction for U.S. federal income tax purposes between transferors and transferees of our units each month based upon the ownership of our units on the first day of each month, instead of on the basis of the date a particular unit is transferred. The U.S. Department of the Treasury adopted final Treasury Regulations allowing a similar monthly simplifying convention for taxable years beginning on or after August 3, 2015. However, such final regulations do not specifically authorize the use of the proration method we have adopted. If the IRS were to challenge our proration method or new Treasury regulations were issued, we may be required to change the allocation of items of income, gain, loss and deduction among our unitholders.
A unitholder whose common units are loaned to a "short seller" to cover a short sale of common units may be considered as having disposed of those common units. If so, such unitholder would no longer be treated for federal income tax purposes as a partner with respect to those common units during the period of the loan and may recognize gain or loss from the disposition.

Because a unitholder whose common units are loaned to a "short seller" to cover a short sale of common units may be considered as having disposed of the loaned common units, such unitholder may no longer be treated for federal income tax purposes as a partner with respect to those common units during the period of the loan to the short seller and may recognize gain or loss from such disposition. Moreover, during the period of the loan to the short seller, any of our income, gain, loss or deduction with respect to those common units may not be reportable by the unitholder and any cash distributions received by the unitholder as to those common units could be fully taxable as ordinary income. Therefore, our unitholders desiring to assure their status as partners and avoid the risk of gain recognition from a loan to a short seller are urged to consult a tax advisor to discuss whether it is advisable to modify any applicable brokerage account agreements to prohibit their brokers from loaning their common units.

We have adopted certain valuation methodologies and monthly conventions for U.S. federal income tax purposes that may result in a shift of income, gain, loss and deduction between our general partner and our unitholders. The IRS may challenge this treatment, which could adversely affect the value of the common units.

When we issue additional units, or engage in certain other transactions, we will determine the fair market value of our assets and allocate any unrealized gain or loss attributable to our assets to the capital accounts of our unitholders and our general partner. Our methodology may be viewed as understating the value of our assets. In that case, there may be a shift of income, gain, loss and deduction between certain unitholders and our general partner, which may be unfavorable to such unitholders. Moreover, under our valuation methods, subsequent purchasers of common units may have a greater portion of their Internal Revenue Code Section 743(b) adjustment allocated to our tangible assets and a lesser portion allocated to our intangible assets. The IRS may

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challenge our valuation methods, or our allocation of the Section 743(b) adjustment attributable to our tangible and intangible assets, and allocations of taxable income, gain, loss and deduction between our general partner and certain of our unitholders.

A successful IRS challenge to these methods or allocations could adversely affect the amount of taxable income or loss being allocated to our unitholders. It also could affect the amount of taxable gain from our unitholders' sale of common units and could have a negative impact on the value of the common units or result in audit adjustments to our unitholders' tax returns without the benefit of additional deductions.

As a result of investing in our common units, our unitholders will likely be subject to state and local taxes and return filing requirements in jurisdictions where we operate or own or acquire properties.

In addition to federal income taxes, our unitholders will likely be subject to other taxes, including state and local taxes, unincorporated business taxes and estate, inheritance or intangible taxes that are imposed by the various jurisdictions in which we conduct business or own property now or in the future, even if they do not live in any of those jurisdictions. Our unitholders will likely be required to file state and local income tax returns and pay state and local income taxes in some or all of these various jurisdictions. Further, our unitholders may be subject to penalties for failure to comply with those requirements. We currently own property and conduct business in a number of states, most of which currently impose a personal income tax on individuals, and most of which also impose an income or similar tax on corporations and certain other entities. As we make acquisitions or expand our business, we may own property or conduct business in additional states that impose an income tax or similar tax. In certain states, tax losses may not produce a tax benefit in the year incurred and also may not be available to offset income in subsequent tax years. Some states may require us, or we may elect, to withhold a percentage of income from amounts to be distributed to a unitholder who is not a resident of the state. Withholding, the amount of which may be greater or less than a particular unitholders' income tax liability to the state, generally does not relieve a nonresident unitholder from the obligation to file an income tax return. Amounts withheld may be treated as if distributed to unitholders for purposes of determining the amounts distributed by us.

Compliance with and changes in tax laws could adversely affect our performance.

We are subject to extensive tax laws and regulations, including federal and state income taxes and transactional taxes such as excise, sales/use, payroll, franchise and ad valorem taxes. New tax laws and regulations and changes in existing tax laws and regulations are continuously being enacted that could result in increased tax expenditures in the future. Many of these tax liabilities are subject to audits by the respective taxing authority. These audits may result in additional taxes as well as interest and penalties.

Item 1B. Unresolved Staff Comments.

None.

Item 2. Properties

Our material properties consist of our principal executive offices, gathering systems, processing plants, transportation systems and storage facilities. Our principal executive offices are located in approximately 162,053 square feet of leased office space at One Leadership Square, 211 North Robinson Avenue, Suite 150, Oklahoma City, Oklahoma 73102. For descriptions of the location and general character of our other material properties, please see Item 1. "Business—Our Assets and Operations."

Our processing plants are located on fee property, except for our Roger Mills plant which is located on leased property. Our other gathering, processing, transportation, and storage assets are located on property that we have the right to use under easements, leases, licenses, or permits granted by governmental agencies, American Indian tribes, railroads, utilities, and other third parties. In some cases, title to our properties or other land rights may be subject to renewals, require periodic payments, or be subject to revocation at the option of the grantor. For example, certain easements granted across American Indian allotted land to which title is held in trust by the United States are subject to renewal, and certain licenses and permits granted by governmental agencies are subject to revocation at the option of the grantor. In other cases, title to our property or other land rights may be subject to encumbrances, restrictions, or imperfections. For example, our title in certain instances may be subject to liens that are not subordinated to our rights, and our title in certain locations may reflect names of predecessors until we have made the appropriate filings. We believe that we generally have sufficient title to our properties and other land rights necessary to operate our assets and conduct our business, subject to such renewals, period payments, revocation rights, restrictions, encumbrances and imperfections that do not materially either detract from the value of our assets or interfere with the conduct of our business.

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Item 3. Legal Proceedings

In the normal course of business, we are confronted with issues or events that may result in a contingent liability. These generally relate to lawsuits or claims made by third parties, including governmental agencies. When appropriate, management consults with legal counsel and other appropriate experts to assess the claim. If, in management's opinion, we have incurred a probable loss as set forth by GAAP, an estimate is made of the loss and the appropriate accounting entries are reflected in our Consolidated Financial Statements. At the present time, based on currently available information, management 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 our financial statements and would not have a material adverse effect on our 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

Market Information

Our common units are listed on the NYSE under the symbol "ENBL." As of February 1, 2019, there were 433,247,600 common units outstanding and approximately 11 unitholders of record of our common units. This number does not include unitholders whose units are held in trust by other entities. The actual number of unitholders is greater than the number of holders of record.

Equity Compensation Plans

The information relating to our equity compensation plans required by Item 5 is incorporated by reference to such information as set forth in Item 12. "Security Ownership of Certain Beneficial Owners and Management and Related Unitholder Matters" contained herein.

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Item 6. Selected Financial Data

The following tables set forth, for the periods and as of the dates indicated, the selected historical financial and operating data of Enable Midstream Partners, LP, which is derived from the historical books and records of the Partnership. The selected historical financial data should be read together with Item 7. “Management’s Discussion and Analysis of Financial Condition and Results of Operations” and the consolidated financial statements and accompanying notes in Item 8. “Financial Statements and Supplementary Data.”

	Year Ended December 31,				
	2018	2017	2016	2015	2014
	(In millions, except for per unit data)				
Results of Operations Data:					
Revenues [1]	$3,431	$2,803	$2,272	$2,418	$3,367
Cost of natural gas and natural gas liquids, excluding depreciation and amortization [1]	1,819	1,381	1,017	1,097	1,914
Operation and maintenance, General and administrative	501	464	465	522	527
Depreciation and amortization	398	366	338	318	276
Impairments	—	—	9	1,134	8
Taxes other than income tax	65	64	58	59	56
Operating income (loss)	648	528	385	(712)	586
Interest expense	(152)	(120)	(99)	(90)	(70)
Equity in earnings of equity method affiliates	26	28	28	29	20
Other, net	—	—	—	2	(1)
Income (loss) before income taxes	522	436	314	(771)	535
Income tax (benefit) expense	(1)	(1)	1	—	2
Net income (loss)	$523	$437	$313	$(771)	$533
Less: Net income (loss) attributable to noncontrolling interests	2	1	1	(19)	3
Net income (loss) attributable to limited partners	$521	$436	$312	$(752)	$530
Less: Series A Preferred Unit distributions	36	36	22	—	—
Net income (loss) attributable to common and subordinated units	$485	$400	$290	$(752)	$530
Basic earnings (loss) per common limited partner unit [2]	$1.12	$0.92	$0.69	$(1.78)	$1.29
Diluted earnings (loss) per common limited partner unit [2]	$1.11	$0.92	$0.69	$(1.78)	$1.28
Basic and diluted earnings (loss) per subordinated limited partner unit [3]	$—	$0.93	$0.68	$(1.78)	$1.28
Distributions declared per unit [4]					$0.4534
Distributions declared per unit [5]	$1.2720	$1.2720	$1.2720	$1.2645	$0.8577

(1) Revenues and Cost of natural gas and natural gas liquids, excluding depreciation and amortization are shown under the guidance of ASC 606 for 2018 and under ASC 605 for 2017 and prior.

(2) Historical basic and diluted earnings per common limited partner unit reflects the 1 for 1.279082616 reverse unit split effected on March 25, 2014.

(3) Basic and diluted earnings per subordinated unit reflect net income (loss) attributable to the Partnership for periods subsequent to its IPO, as no subordinated units were outstanding prior to this date. 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.

(4) Distributions attributable to periods prior to the IPO are in accordance with the First Amended and Restated Agreement of Limited Partnership. Distributions declared per unit prior to the IPO relate to common units, as no

subordinated units were outstanding prior to the date of the IPO.

(5) Distributions attributable to periods subsequent to the IPO are in accordance with the Partnership Agreement. Distributions declared per unit relate to common and subordinated units.

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	December 31,				
	2018	2017	2016	2015	2014
	(In millions)				
Balance Sheet Data (at period end):					
Property, plant and equipment, net	$10,871	$10,355	$10,143	$10,131	$9,582
Total assets	12,444	11,593	11,212	11,226	11,837
Total debt	4,278	3,450	2,993	3,270	2,544
Partners' Equity	7,618	7,654	7,794	7,531	8,823

	Year Ended December 31,				
	2018	2017	2016	2015	2014
	(In millions, except for operating data)				
Cash Flow Data:					
Net cash flows provided by (used in):					
Operating activities	$924	$834	$721	$726	$769
Investing activities	(1,154)	(706)	(367)	(946)	(815)
Financing activities	233	(132)	(335)	212	(50)
Other Financial Data [(1)]:					
Gross margin	$1,612	$1,422	$1,255	$1,321	$1,453
Adjusted EBITDA	1,074	924	873	801	881
DCF	760	660	639	538	634
Operating Data:					
Natural gas gathered volumes—TBtu	1,637	1,300	1,143	1,148	1,221
Natural gas gathered volumes—TBtu/d	4.48	3.56	3.13	3.14	3.34
Natural gas processed volumes—TBtu	877	715	658	651	569
Natural gas processed volumes—TBtu/d	2.40	1.96	1.80	1.78	1.56
NGLs produced—MBbl/d [(2)]	129.98	90.11	78.70	73.55	66.74
NGLs sold—MBbl/d [(2)(3)]	132.06	92.21	78.16	75.55	68.67
Condensate sold—MBbl/d	5.90	4.79	5.27	5.13	4.38
Crude oil and condensate gathered volumes—MBbl/d [(4)]	41.07	25.56	25.00	13.86	3.64
Transported volumes—TBtu	2,028	1,838	1,788	1,814	1,808
Transported volumes—TBtu/d	5.56	5.04	4.88	4.97	4.95
Interstate firm contracted capacity—Bcf/d	5.94	6.21	7.04	7.19	7.73
Intrastate average deliveries—TBtu/d	2.08	1.88	1.72	1.84	1.61

(1) See "Reconciliations of Non-GAAP Financial Measures" in Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations" for a reconciliation of Gross margin, Adjusted EBITDA and DCF to their most directly comparable financial measure calculated and presented in accordance with GAAP.

(2) Excludes condensate.

(3) NGLs sold includes volumes of NGLs withdrawn from inventory or purchased for system balancing purposes.

(4) Initial operation of our crude oil gathering system began on November 1, 2013.

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

The following discussion and analysis of our financial condition and results of operations should be read in conjunction with our consolidated financial statements and notes included in this report.

Overview

We are a Delaware limited partnership formed in May 2013 to own, operate and develop strategically located midstream assets. We completed our IPO in April 2014, and we are traded on the NYSE under the symbol “ENBL.” We were formed by CenterPoint Energy, OGE Energy and ArcLight. Our general partner is owned by CenterPoint Energy and OGE Energy.

Our Operations

Our assets and operations are organized into two reportable segments: (i) gathering and processing and (ii) transportation and storage. Our gathering and processing segment primarily provides natural gas gathering and processing services to our producer customers and crude oil, condensate and produced water gathering services to our producer and refiner customers. Our 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.

Our gathering and processing assets include approximately 13,400 miles of natural gas gathering pipelines, 15 natural gas processing plants with approximately 2.6 Bcf/d of processing capacity and approximately 1,160,900 horsepower of compression as of December 31, 2018 in the Anadarko, Arkoma and Ark-La-Tex Basins. In addition, our gathering and processing assets include approximately 150 miles of crude oil and condensate gathering pipelines (including VPP) serving the Anadarko Basin, 175 miles of crude oil gathering pipelines and 150 miles of produced water gathering pipelines serving the Williston Basin.

Our transportation and storage assets include approximately 10,090 miles of natural gas intrastate and interstate transportation pipelines across nine states, eight natural gas storage facilities with approximately 84.5 Bcf of storage capacity and approximately 837,600 horsepower of compression. As part of these transportation and storage assets, we own a 50% interest in, and provide field operations for, SESH, an approximately 290-mile interstate pipeline providing access to the Southeast power generation market.

Items Affecting the Comparability of Our Financial Results

The comparability of our current financial condition and results of operations with our historical financial conditions and results of operations may be affected by the items described below.

Capitalization

On February 18, 2016, the Partnership completed the private placement of 14,520,000 Series A Preferred Units 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 accounted for 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. In connection with the private placement, Enable GP adopted the Partnership's Third Amended and Restated Agreement of Limited Partnership on February 18, 2016, which, among other things, authorized the issuance of Series A Preferred Units. The Series A Preferred Units rank senior to the Partnership's common units with respect to the payment of distributions and the 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; receive on a non-cumulative basis if and when declared by the general partner, a quarterly cash distribution, subject to certain adjustments, equal to an annual rate of 10% 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 LIBOR plus 850 bps on the stated liquidation preference thereafter.

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

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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.

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). The proceeds were used for general partnership purposes. For the year ended December 31, 2017, the Partnership sold an aggregate of 18,500 common units under the ATM Program, which generated proceeds of approximately $303,000 (net of approximately $3,000 commissions). The Partnership incurred approximately $345,000 of expenses associated with the filing of the registration statements for the ATM Program. 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.

Financing

On July 31, 2015, the Partnership entered into a term loan agreement providing for an unsecured, three-year $450 million term loan agreement (2015 Term Loan Agreement). In May 2018, the Partnership used a portion of the proceeds from the issuance of the 2028 Notes to repay all amounts outstanding under the 2015 Term Loan Agreement.

On March 9, 2017, the Partnership completed the public offering of $700 million 4.400% Senior Notes due 2027 (2027 Notes). The Partnership received net proceeds of approximately $691 million. The proceeds were used for general partnership purposes, including to repay amounts outstanding under the 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, 5-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.

On May 10, 2018, the Partnership completed the public offering of $800 million aggregate principal amount of its 4.950% Senior Notes due 2028 (2028 Notes). 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.

Trends and Outlook

We expect our business to continue to be impacted by the trends affecting our industry that are discussed below. Our outlook is based on assumptions regarding the impact of these trends that we have developed by interpreting the information currently available to us. If our assumptions or interpretation of available information prove to be incorrect, our future financial condition and results of operations may differ materially from our expectations.

Commodity Price Environment

Our 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 our systems, and the volumes on our systems are negatively impacted if producers decrease drilling and production in those areas served. Both our gathering and processing segment and our transportation and storage segment can be impacted by drilling and production. Our gathering and processing segment primarily serve producers, and many producers utilize the services provided by our transportation and storage segment. A decrease in volumes will decrease the cash flows from our systems. In addition, our processing arrangements expose us to commodity price fluctuations. For more information regarding the impact of commodity prices, drilling and production on the volumes on our systems as well as our exposure to commodity prices under our processing arrangements, see Item 1A. “Risk Factors—Risks Related to Our Business.”

We have attempted to mitigate the impact of commodity prices on our business by entering into hedges, focusing on contracting fee-based business and converting existing commodity-based contracts to fee-based contracts. For additional information regarding our commodity price risk, see Item 7A. “Quantitative and Qualitative Disclosures About Market Risk—Commodity Price Risk.”

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Commodity Supply and Demand Dynamics

Our long-term view is that natural gas and crude oil production in the United States will increase. There has been a fundamental shift in the United States natural gas and crude oil production towards tight gas formations and shale plays. Advancements in technology have allowed producers to efficiently extract natural gas and crude oil from these formations and plays. As a result, the proven reserves of natural gas and crude oil in the United States have significantly increased.

Natural gas continues to be a critical component of energy demand in the United States. Over the long term, management believes that the prospects for continued natural gas demand are favorable and will be driven by population and economic growth, as well as the continued displacement of coal-fired power plants by natural gas-fired power plants due to the price of natural gas and stricter government environmental regulations on the mining and burning of coal. We believe that increasing consumption of natural gas over the long term in these sectors will continue to drive demand for our natural gas gathering, processing, transportation and storage services.

Capital Market Volatility

We may access the capital markets to fund our expansion capital expenditures. Historically, unit prices of midstream master limited partnerships have experienced periods of volatility. In addition, because our common units are yield-based securities, rising market interest rates could impact the relative attractiveness of our common units to investors. Further, fluctuations in energy and commodity prices can create volatility in our common unit prices, which could impact investor appetite for our common units. Volatility in energy and commodity prices, as well as other macro-economic factors could impact the relative attractiveness of our debt securities to investors. As a result of capital market volatility, we may be unable to issue equity securities or debt on satisfactory terms, or at all, which may limit our ability to expand our operations or make future acquisitions. See Part I, Item 1A. “Risk Factors—Risks Related to Our Business.”

Regulatory Compliance

The regulation of gathering and transmission pipelines, storage and related facilities by FERC and other federal and state regulatory agencies, including the DOT, has a significant impact on our business. For example, the DOT’s Pipeline and Hazardous Materials Safety Administration, or PHMSA, has established pipeline integrity management programs that require more frequent inspections of pipeline facilities and other preventative measures, which may increase our compliance costs and increase the time it takes to obtain required permits. Additionally, increased regulation of oil and natural gas producers, including regulation associated with hydraulic fracturing, could reduce regional supply of oil and natural gas and therefore throughput on our gathering systems. For more information, see Item 1. “Business—Rate and Other Regulation.”

Measures We Use to Evaluate Results of Operations

We use a variety of operational and financial measures to evaluate our results of operations and our financial condition and to manage our business. The measures that we use to analyze our business include: (i) throughput volumes, (ii) operation and maintenance and general and administrative expenses, (iii) Gross margin, (iv) Adjusted EBITDA, (v) Adjusted interest expense, (vi) DCF and (vii) Distribution coverage ratio.

Throughput Volumes

Throughput volume is operating data. The volumes of natural gas, crude oil, condensate and produced water on our gathering and processing and transportation and storage systems depends significantly on the level of production from the basins served by our systems and the wells connected to our systems. Gathering and processing as well as transportation and storage can be impacted by the wells connected to our system because the customers for our gathering and processing services are primarily producers, and many producers utilize our transportation and storage services. Aggregate production volumes are impacted by the overall amount of drilling and completion activity, as production must be maintained or increased by new drilling or other activity, because the production rates of wells decline over time. Producers' willingness to engage in new drilling is determined by a number of factors, which include: the prevailing and projected prices of natural gas, NGLs and crude oil; the cost to drill and operate a well; the availability and cost of capital; technological advances in drilling and production techniques; and environmental and other government regulations. We generally expect the level of drilling to positively correlate with long-term trends in commodity prices. Similarly, we generally expect the level of production to positively correlate with drilling activity.

To maintain and increase throughput volumes on our gathering and processing systems, we must compete to connect to new

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wells as production from existing wells declines. We actively monitor drilling activity in the areas served by our gathering and processing systems to pursue new customers and new wells. To maintain and increase the throughput volumes on our transportation and storage systems, we must compete for the business of producers and other customers who have existing and new sources of supply in the basins served by our systems, and we must compete for the business of power plants, LDCs, industrial end users and other customers who have existing and new sources of demand in the markets served by our systems.

We actively monitor customer activity in the basins and markets served by our transportation and storage systems to pursue new supply and demand opportunities. In both gathering and processing and transportation and storage, we compete for customers based on service offerings, operating flexibility, receipt and delivery points, available capacity and price.

Operation and Maintenance and General and Administrative Expenses

Operation and Maintenance and General and Administrative Expenses is a GAAP financial measure. We seek to maximize the profitability of our operations by effectively managing operation and maintenance and general and administrative expenses. These expenses are comprised primarily of labor expenses, lease costs, utility costs, insurance premiums, repair expenses and maintenance expenses. These labor expenses, lease costs, utility costs and insurance premiums have remained relatively stable across periods in the current low inflation environment, but repair and maintenance expense can fluctuate from period to period based on the activities performed and the timing of expenses. The level of drilling activity impacts competition for personnel, supplies and equipment. Increased competition could place upward pressure on the cost of labor, supplies and miscellaneous equipment.

Use of Non-GAAP Financial Measures

Gross margin, Adjusted EBITDA, Adjusted interest expense, DCF and Distribution coverage ratio are not financial measures presented in accordance with GAAP. These financial measures are subject to adjustments that have the effect of excluding amounts that are included in the most directly comparable measure calculated and presented in accordance with GAAP. Because these non-GAAP financial measures exclude amounts that are included in the most directly comparable GAAP financial measures, they have important limitations as an analytical tool. We nevertheless believe that the presentation of these non-GAAP financial measures provides useful information to investors regarding our financial condition and results of operations because they are the financial measures used by management to evaluate and manage our business.

We have provided definitions for Gross margin, Adjusted EBITDA, Adjusted interest expense, DCF and Distribution coverage ratio. Although the use of non-GAAP financial measures with the same or similar titles is common in our industry, comparability may vary from one company to another. Because Gross margin, Adjusted EBITDA, Adjusted interest expense, DCF and Distribution coverage ratio may be defined differently by other companies in our industry, our presentation of these non-GAAP financial measures may not be directly comparable to non-GAAP financial measures of other companies with the same or similar titles.

Gross margin is most directly comparable to the GAAP financial measure revenue. When used as a financial measure, Adjusted EBITDA is most directly comparable to the GAAP financial measure net income attributable to limited partners. When used as a liquidity measure, Adjusted EBITDA is most directly comparable to the GAAP liquidity measure net cash provided by operating activities. Adjusted interest expense is most directly comparable to the GAAP financial measure interest expense. DCF is most directly comparable to the GAAP financial measure net income attributable to limited partners. Distribution coverage ratio is computed utilizing DCF, which is most directly comparable to the GAAP financial measure net income attributable to limited partners. These non-GAAP financial measures should not be considered a substitute for the most directly comparable financial measures. Reconciliations of these non-GAAP financial measures to their most directly comparable GAAP financial measures are provided in "—Reconciliations of non-GAAP Financial Measures" below.

Gross Margin

We define gross margin as total revenues minus costs of natural gas and natural gas liquids, excluding depreciation and amortization. Total revenues consist of the fees that we charge our customers and the sales price of natural gas and natural liquids that we sell. The cost of natural gas and natural gas liquids consists of the purchase price of natural gas and natural gas liquids that we purchase. We deduct the cost of natural gas and natural gas liquids from total revenue to arrive at a measure of the core profitability of our mix of fee-based and commodity-based customer arrangements. We use gross margin as a performance measure to analyze the core profitability of our customer arrangements. Please read "—Results of Operations" and "—Use of Non-GAAP Financial Measures."

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Adjusted EBITDA

We define Adjusted EBITDA as net income (loss) attributable to limited partners plus depreciation and amortization expense, interest expense, income tax expense, distributions received from equity method affiliate in excess of equity earnings, non-cash equity-based compensation, impairments, changes in the fair value of derivatives and certain other non-cash losses (including losses on sales of assets and write-downs of materials and supplies), less the noncontrolling interests share of Adjusted EBITDA. We use Adjusted EBITDA to evaluate our operating profitability unburdened by our capital structure. Because Adjusted EBITDA adds back to net income the non-cash accounting charges of depreciation and amortization and disregards interest paid on debt financing and income taxes on earnings, we believe that it is useful for measuring our operating cash flow. However, Adjusted EBITDA does not measure, and should not be confused with, our actual cash flow which accounts for interest paid on debt financing, income taxes and other cash charges.

Adjusted Interest Expense

We define adjusted interest expense as interest expense plus amortization of premium on long-term debt and capitalized interest, less amortization of debt costs and discount on long-term debt. We use adjusted interest expense to assess the Partnership's ability to incur and service debt and fund capital expenditures.

DCF

We define DCF as Adjusted EBITDA, as further adjusted for Series A Preferred Unit distributions, Adjusted interest expense, maintenance capital expenditures, compensation expense for distribution equivalent rights of phantom and performance units and current income taxes. We use DCF as a proxy for measuring cash available for distributions. However, DCF does not reflect the cash reserves set aside for our operations by our Board of Directors prior to determining the amount of our distributions to our limited partners, and should not be confused with our actual cash available for distribution. For more information on the determination of our distributions by our Board of Directors see "Liquidity and Capital Resources—Distributions of Available Cash" below.

Distribution Coverage Ratio

We define Distribution coverage ratio as DCF divided by distributions related to common and subordinated unitholders. DCF is most directly comparable to net income attributable to limited partners, which is reconciled below. We use Distribution coverage ratio to assess the ability of the Partnership's assets to generate sufficient cash flow to make distributions to its partners.

Results of Operations

The following tables summarizes the composition of our results of operations for the years ended December 31, 2018, 2017 and 2016.

December 31, 2018	Gathering and Processing	Transportation and Storage	Eliminations	Enable Midstream Partners, LP
	(In millions)			
Product sales	$2,016	$ 625	$ (535)	$ 2,106
Service revenue	802	537	(14)	1,325

Total Revenues	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
Gross margin [1]	1,077	534	1	1,612
Operation and maintenance, General and administrative	312	189	—	501
Depreciation and amortization	263	135	—	398
Impairments	—	—	—	—
Taxes other than income tax	38	27	—	65
Operating income	$464	$ 183	$ 1	$ 648
Equity in earnings of equity method affiliate	$—	$ 26	$ —	$ 26

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December 31, 2017	Gathering and Processing	Transportation and Storage	Eliminations	Enable Midstream Partners, LP
	(In millions)			
Product sales	$1,538	$ 621	$ (506)	$ 1,653
Service revenue	632	525	(7)	1,150
Total Revenues	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
Gross margin [1]	885	542	(5)	1,422
Operation and maintenance, General and administrative	289	179	(4)	464
Depreciation and amortization	232	134	—	366
Taxes other than income tax	37	27	—	64
Operating income	$327	$ 202	$ (1)	$ 528
Equity in earnings of equity method affiliate	$—	$ 28	$ —	$ 28

December 31, 2016	Gathering and Processing	Transportation and Storage	Eliminations	Enable Midstream Partners, LP
	(In millions)			
Product sales	$1,081	$ 479	$ (388)	$ 1,172
Service revenue	559	545	(4)	1,100
Total Revenues	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
Gross margin [1]	725	532	(2)	1,255
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
Equity in earnings of equity method affiliate	$—	$ 28	$ —	$ 28

(1) Gross margin is a non-GAAP measure and is defined and reconciled to its most directly comparable financial measures calculated and presented below under the caption Reconciliations of Non-GAAP Financial Measures.

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	Year Ended December 31,		
	2018	2017	2016
Operating Data:			
Natural gas gathered volumes—TBtu	1,637	1,300	1,143
Natural gas gathered volumes—TBtu/d	4.48	3.56	3.13
Natural gas processed volumes—TBtu	877	715	658
Natural gas processed volumes—TBtu/d	2.40	1.96	1.80
NGLs produced—MBbl/d (1)	129.98	90.11	78.70
NGLs sold—MBbl/d (1)(2)	132.06	92.21	78.16
Condensate sold—MBbl/d	5.90	4.79	5.27
Crude oil and condensate gathered volumes—MBbl/d	41.07	25.56	25.00
Transported volumes—TBtu	2,028	1,838	1,788
Transported volumes—TBtu/d	5.56	5.04	4.88
Interstate firm contracted capacity—Bcf/d	5.94	6.21	7.04
Intrastate average deliveries—TBtu/d	2.08	1.88	1.72

	Year Ended December 31,		
	2018	2017	2016
Operating Data By Basin:			
Anadarko			
Natural gas gathered volumes—TBtu/d	2.21	1.81	1.65
Natural gas processed volumes—TBtu/d	1.99	1.61	1.47
NGLs produced—MBbl/d (1)	113.63	76.37	65.19
Crude oil and condensate gathered volumes—MBbl/d	12.14	—	—
Arkoma			
Natural gas gathered volumes—TBtu/d	0.55	0.55	0.62
Natural gas processed volumes—TBtu/d	0.10	0.09	0.10
NGLs produced—MBbl/d (1)	6.55	4.79	4.86
Ark-La-Tex			
Natural gas gathered volumes—TBtu/d	1.72	1.20	0.86
Natural gas processed volumes—TBtu/d	0.31	0.26	0.23
NGLs produced—MBbl/d (1)	9.80	8.95	8.65
Williston			
Crude oil gathered volumes—MBbl/d	28.93	25.56	25.00

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

Gathering and Processing

2018 compared to 2017. Our gathering and processing segment reported operating income of $464 million for 2018 compared to $327 million for 2017. The difference of $137 million in operating income between periods was primarily due to a $192 million increase in gross margin. This was partially offset by a $31 million increase in depreciation and amortization, a $23 million increase in operation and maintenance and general and administrative expenses and a $1 million increase in taxes other than income tax in 2018.

Our gathering and processing segment revenues increased $648 million in 2018. The increase was primarily due to the following:

Product Sales:

- revenues from NGL sales increased $459 million resulting from higher average NGL prices, higher processed volumes and increased recoveries of ethane in the Anadarko and Ark-La-Tex Basins, inclusive of a $29 million decrease due to the implementation of ASC 606, and
- changes in the fair value of natural gas, condensate and NGL derivatives increased $23 million.

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These increases were partially offset by:

- revenues from natural gas sales decreased $4 million due to a $44 million decrease related to the implementation of ASC 606, partially offset by a $40 million increase due to higher sales volumes offset by a lower average price.

Service Revenues:

- processing service revenues increased $128 million resulting from higher processed volumes primarily under fixed processing arrangements in the Anadarko and Ark-La-Tex Basins, inclusive of a $70 million increase due to the implementation of ASC 606,
- natural gas gathering revenues increased $37 million due to higher fees and gathered volumes in the Anadarko and Ark-La-Tex Basins, inclusive of a $46 million decrease due to the implementation of ASC 606, and
- crude oil, condensate and produced water gathering revenues increased $9 million driven by a $5 million increase in the Anadarko Basin due to the acquisition of EOCS and a $4 million increase in the Williston Basin due to higher gathered volumes, partially offset by a reduction in average rates.

These increases were partially offset by a $4 million decrease in intercompany management fees.

Our gathering and processing segment gross margin increased $192 million in 2018. The increase was primarily due to the following:

- processing service fees increased $128 million resulting from higher processed volumes primarily under fixed processing arrangements in the Anadarko and Ark-La-Tex Basins, inclusive of a $70 million increase due to the implementation of ASC 606,
- natural gas gathering fees increased $37 million due to higher fees and gathered volumes in the Anadarko and Ark-La-Tex Basins, inclusive of a $46 million decrease due to the implementation of ASC 606,
- changes in the fair value of natural gas, condensate and NGL derivatives increased $23 million,
- revenues from NGL sales less the cost of NGLs increased $10 million inclusive of a $64 million decrease due to the implementation of ASC 606, partially offset by higher average NGL prices and higher processed volumes in the Anadarko and Ark-La-Tex Basins, and
- crude oil, condensate and produced water gathering revenues increased $9 million driven by a $5 million increase in the Anadarko Basin due to the acquisition of EOCS and a $4 million increase in the Williston Basin due to higher gathered volumes, partially offset by a reduction in average rates.

These increases were partially offset by:

- revenues from natural gas sales less the cost of natural gas decreased $11 million primarily due to a $36 million decrease due to lower average prices partially offset by higher sales volumes and a $15 million increase in fuel costs, inclusive of a $40 million increase due to the implementation of ASC 606, and
- a $4 million decrease in intercompany management fees.

Our gathering and processing segment operation and maintenance and general and administrative expenses increased $23 million in 2018. The increase was primarily due to an $11 million increase related to maintenance on treating plants as a result of increased activity on our Ark-La-Tex assets, an $8 million increase in compressor rental expenses due to increased rental units, an $8 million increase in materials and supplies and contract services as a result of additional assets in service, a $5 million increase in payroll-related costs and a $4 million increase in acquisition costs. These were partially offset by a $7 million decrease due to a loss on the disposal of assets in 2017, for which there were no comparable items in 2018, a $5 million decrease due to an increase in capitalized overhead costs as a result of increased capital projects in 2018 and a $2 million change in the allowance for doubtful accounts due to the collection of accounts receivable in the year ended December 31, 2018 that were previously included in the allowance for doubtful accounts.

Our gathering and processing segment depreciation and amortization expense increased $31 million in 2018 due to additional assets placed in service.

Our gathering and processing segment taxes other than income tax increased $1 million in 2018 due to higher accrued ad valorem taxes due to additional assets placed in service.

2017 compared to 2016. Our gathering and processing segment reported operating income of $327 million for 2017 compared to $196 million for 2016. The difference of $131 million in operating income between periods was primarily due to a $160 million increase in gross margin and no impairments recognized in 2017 as compared to $9 million of impairments recognized in 2016.

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This was partially offset by a $20 million increase in depreciation and amortization, a $13 million increase in operation and maintenance and general and administrative expenses and a $5 million increase in taxes other than income tax in 2017.

Our gathering and processing segment revenues increased $530 million in 2017. The increase was primarily due to a $315 million increase in revenues from NGL sales resulting from higher average NGL prices and higher processed volumes in the Anadarko Basin, a $116 million increase in revenues from sales of natural gas as a result of higher average natural gas prices and higher gathering volumes in the Anadarko and Ark-La-Tex Basins, a $39 million increase in natural gas gathering revenues due to higher fees and gathering volumes in the Anadarko and Ark-La-Tex Basins and increased billings under minimum volume commitments in the Arkoma Basin, a $28 million increase in processing revenues resulting from higher processed volumes and from a percent-of-proceeds contract that was converted to a fee-based contract in the fourth quarter of 2016, a $27 million increase in revenues from changes in the fair value of condensate and NGL derivatives, a $3 million increase due to increased water transportation revenues, a $2 million increase due to crude oil transportation revenues in the Williston Basin and a $2 million increase due to an increase in intercompany management fees. These increases were partially offset by a $4 million decrease in revenues due to a wind-down of third-party measurement and communication services in 2017.

Our gathering and processing segment gross margin increased $160 million in 2017. The increase was primarily due to a $62 million 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, a $40 million increase in processing margins resulting from higher average NGL prices and higher processed volumes in the Anadarko Basin, a $32 million 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, a $27 million increase in gross margin from changes in the fair value of condensate and NGL derivatives, a $3 million increase due to increased water transportation services, a $2 million increase due to crude oil transportation services in the Williston Basin and a $2 million increase due to an increase in intercompany management fees. These increases were partially offset by a $6 million decrease in gross margin associated with our annual fuel rate determination and a $4 million decrease in gross margin due to a wind-down of third-party measurement and communication services in 2017.

Our gathering and processing segment operation and maintenance and general and administrative expenses increased $13 million in 2017. The increase was primarily due to a $5 million increase in payroll-related costs, a $4 million increase in materials and supplies and contract services, a $3 million increase due to a reduction in capitalized overhead costs, a $2 million increase in acquisition costs associated with the Align acquisition and a $1 million increase in equipment rentals, partially offset by a $1 million decrease in loss on sale of assets.

Our gathering and processing segment depreciation and amortization expense increased $20 million in 2017 due to additional assets placed in service.

Our gathering and processing segment recognized no impairments in 2017 and $9 million in 2016 on our Service Star business line.

Our gathering and processing segment taxes other than income tax increased $5 million in 2017 due to higher accrued ad valorem taxes due to additional assets placed in service.

Transportation and Storage

2018 compared to 2017. Our transportation and storage segment reported operating income of $183 million for 2018 as compared to $202 million for 2017. The difference of $19 million in operating income between periods was primarily due to an $8 million decrease in gross margin, a $10 million increase in operation and maintenance and general and administrative expenses and a $1 million increase in depreciation and amortization in 2018.

Our transportation and storage segment revenues increased $16 million in 2018. The increase was primarily due to the following:

Product Sales:

- revenues from natural gas sales increased $27 million primarily due to higher volumes, partially offset by lower average prices and inclusive of a $4 million decrease due to the implementation of ASC 606, and
- revenues from NGL sales increased $3 million due to higher average prices and higher volumes.

These increases were partially offset by a $26 million decrease in changes in the fair value of natural gas derivatives.

Service Revenues:

- other firm transportation and storage services increased $15 million due to new interstate and intrastate transportation contracts, and
- volume-dependent transportation revenues increased $14 million 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.

These increases were partially offset by:

- firm transportation services between Carthage, Texas and Perryville, Louisiana decreased $17 million due to contract expirations during 2017.

Our transportation and storage segment gross margin decreased $8 million in 2018. The decrease was primarily due the following:

- changes in the fair value of natural gas derivatives decreased $26 million, and
- firm transportation services between Carthage, Texas and Perryville, Louisiana decreased $17 million due to contract expirations during 2017.

These decreases were partially offset by:

- other firm transportation and storage services increased $15 million due to new interstate and intrastate transportation contracts,
- volume-dependent transportation increased $14 million 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
- system management activities increased $6 million.

Our transportation and storage segment operation and maintenance and general and administrative expenses increased $10 million in 2018. The increase was primarily due to a $10 million increase in materials and supplies and contract services, a $2 million increase in loss on retirement of assets, a $1 million increase in information-technology related costs and a $1 million increase in one-time reimbursements associated with an unplanned pipeline outage. These increases were partially offset by a $4 million decrease in intercompany management fees.

Our transportation and storage segment depreciation and amortization expense increased $1 million in 2018 due to additional assets placed in service.

2017 compared to 2016. Our transportation and storage segment reported operating income of $202 million for 2017, as compared to $189 million for 2016. The difference of $13 million in operating income between periods was primarily due to a $10 million increase in gross margin and a $12 million decrease in operation and maintenance and general and administrative expenses in 2017. This was partially offset by an $8 million increase in depreciation and amortization and a $1 million increase in taxes other than income tax in 2017.

Our transportation and storage segment revenues increased $122 million in 2017. The increase was primarily due to a $78 million increase in revenues from higher natural gas sales associated with higher sales volumes and higher average sales prices, a $61 million increase in revenues from changes in the fair value of natural gas derivatives, a $10 million increase in revenues from NGL sales due to an increase in transported volumes and NGL prices and a $5 million increase in revenues from off-system transportation. These increases were partially offset by a $24 million decrease in firm transportation services, which includes a $27 million decrease in firm transportation services between Carthage, Texas, and Perryville, Louisiana. Additionally, we had a $5 million decrease in realized gains on natural gas derivatives and a $1 million decrease in revenues from transportation services for LDCs.

Our transportation and storage segment gross margin increased $10 million in 2017. The increase was primarily due to a $61 million increase in gross margin from changes in the fair value of natural gas derivatives, a $6 million increase in NGL sales due to an increase in transported volumes and NGL prices, a $5 million increase in off-system transportation margins, and a $3 million increase in firm transportation, other than firm transportation services between Carthage, Texas, and Perryville, Louisiana. These increases were partially offset by a $33 million decrease in system management activities and a decrease of $24 million in firm transportation services, which includes a $27 million decrease in firm transportation services between Carthage, Texas, and Perryville, Louisiana. Additionally, we had a $5 million decrease in realized gains on natural gas derivatives and a $1 million decrease in gross margin from transportation services for LDCs.

Our transportation and storage segment operation and maintenance and general and administrative expenses decreased $12 million in 2017. The decrease was primarily due to a $10 million decrease in loss on sale of assets, a $5 million decrease in information-technology related costs and a $3 million decrease in materials and supplies and contract services. These decreases

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were partially offset by a $3 million increase in payroll-related costs, a $2 million increase in intercompany management fees and a $2 million increase due to a reduction in capitalized overhead costs.

Our transportation and storage segment depreciation and amortization expense increased $8 million in 2017 due to additional assets placed in service.

Our transportation and storage segment taxes other than income tax increased by $1 million in 2017 due to higher accrued ad valorem taxes due to additional assets placed in service.

Consolidated Information

	Year Ended December 31,		
	2018	2017	2016
	(In millions)		
Operating Income	$648	$528	$385
Other Income (Expense):			
Interest expense	(152)	(120)	(99)
Equity in earnings of equity method affiliate	26	28	28
Other, net	—	—	—
Total Other Income (Expense)	(126)	(92)	(71)
Income Before Income Taxes	522	436	314
Income tax expense (benefit)	(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	36	36	22
Net Income attributable to common and subordinated units	$485	$400	$290

2018 compared to 2017

Net Income attributable to limited partners. We reported net income attributable to limited partners of $521 million in 2018 compared to $436 million in 2017. The increase in net income attributable to limited partners was primarily due to an increase in operating income of $120 million partially offset by an increase in interest expense of $32 million.

Interest Expense. Interest expense increased by $32 million in 2018 due to an increase in the amount of debt outstanding as well as higher interest rates on the Partnership's outstanding debt as a result of a long-term debt issuance in May 2018 that resulted in the repayment of all amounts outstanding under the Partnership's 2015 Term Loan Agreement, as well as amounts outstanding under our commercial paper program.

2017 compared to 2016

Net Income attributable to limited partners. We reported net income attributable to limited partners of $436 million in 2017 compared to $312 million in 2016. The increase in net income attributable to limited partners was primarily due to an increase in operating income of $143 million partially offset by an increase in interest expense of $21 million.

Interest Expense. Interest expense increased by $21 million in 2017 due to higher interest rates on the Partnership's outstanding debt.

Reconciliations of Non-GAAP Financial Measures

The Partnership has included the non-GAAP financial measures Gross margin, Adjusted EBITDA, Adjusted interest expense, DCF and Distribution coverage ratio in this report based on information in its Consolidated Financial Statements. Gross margin, Adjusted EBITDA, Adjusted interest expense, DCF and Distribution coverage ratio are part of the performance measures that we

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use to manage the Partnership. For definitions and a description of management's use of Gross margin, Adjusted EBITDA, Adjusted interest expense, DCF and Distribution coverage ratio, see "—Measures We Use to Evaluate Results of Operations" above.

Provided below are reconciliations of Gross margin to total revenues, Adjusted EBITDA and DCF to net income attributable to limited partners, Adjusted EBITDA to net cash provided by operating activities and Adjusted interest expense to interest expense, the most directly comparable GAAP financial measures, on a historical basis, as applicable, for each of the periods indicated. Gross margin, Adjusted EBITDA, Adjusted interest expense, DCF and Distribution coverage ratio should not be considered as alternatives to net income, operating income, total revenues, cash flow from operating activities or any other measure of financial performance or liquidity presented in accordance with GAAP. These non-GAAP financial measures have important limitations as analytical tools because they exclude some but not all items that affect the most directly comparable GAAP financial measures. Additionally, because Gross margin, Adjusted EBITDA, Adjusted interest expense, DCF and Distribution coverage ratio may be defined differently by other companies in the Partnership's industry, these measures may not be comparable to similarly titled measures of other companies, thereby diminishing their utility.

	Year Ended December 31,		
	2018	2017	2016
	(In millions)		
Reconciliation of Gross Margin to Total Revenues:			
Consolidated			
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 of natural gas and natural gas liquids (excluding depreciation and amortization)	1,819	1,381	1,017
Gross margin	$1,612	$1,422	$1,255
Reportable Segments			
Gathering and Processing			
Product sales	$2,016	$1,538	$1,081
Service revenue	802	632	559
Total Revenues	2,818	2,170	1,640
Cost of natural gas and natural gas liquids (excluding depreciation and amortization)	1,741	1,285	915
Gross margin	$1,077	$885	$725
Transportation and Storage			
Product sales	$625	$621	$479
Service revenue	537	525	545
Total Revenues	1,162	1,146	1,024
Cost of natural gas and natural gas liquids (excluding depreciation and amortization)	628	604	492
Gross margin	$534	$542	$532

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The following table shows the components of our gross margin for the year ended December 31, 2018.

	Fee-Based Demand/ Commitment/ Guaranteed Return	Volume Dependent	Commodity-Based	Total
Year Ended December 31, 2018				
Gathering and Processing Segment	23 %	49 %	28 %	100 %
Transportation and Storage Segment	88 %	12 %	— %	100 %
Partnership Weighted Average	45 %	36 %	19 %	100 %

	Year Ended December 31,		
	2018	2017	2016
	(In millions, except Distribution coverage ratio)		
Reconciliation of Adjusted EBITDA and DCF to net income attributable to limited partners and calculation of Distribution coverage ratio:			
Net income attributable to limited partners	$521	$436	$312
Depreciation and amortization expense	398	366	338
Interest expense, net of interest income	152	120	99
Income tax (benefit) expense	(1)	(1)	1
Distributions received from equity method affiliate in excess of equity earnings	7	5	15
Non-cash equity-based compensation	16	15	13
Change in fair value of derivatives	(26)	(28)	60
Other non-cash losses (1)	7	11	26
Impairments	—	—	9
Adjusted EBITDA	$1,074	$924	$873
Series A Preferred Unit distributions (2)	(36)	(36)	(31)
Distributions for phantom and performance units (3)	(5)	(2)	—
Adjusted interest expense (4)	(159)	(123)	(103)
Maintenance capital expenditures	(114)	(101)	(101)
Current income taxes	—	(2)	1
DCF	$760	$660	$639
Distributions related to common and subordinated unitholders (5)	$552	$551	$539
Distribution coverage ratio	1.38	1.20	1.18

(1) Other non-cash losses include loss on sale of assets and write-downs of materials and supplies.

(2) This amount represents the quarterly cash distributions on the Series A Preferred Units declared for the years ended December 31, 2018 and 2017. The year ended December 31, 2016 amount includes the prorated quarterly cash distribution on the Series A Preferred Units declared on April 26, 2016. In accordance with the Partnership Agreement, the Series A Preferred Unit distributions are deemed to have been paid out of available cash with respect to the quarter immediately preceding the quarter in which the distribution is made.

(3) Distributions for phantom and performance units represent distribution equivalent rights paid in cash. Phantom unit distribution equivalent rights are paid during the vesting period and performance unit distribution equivalent rights

are paid at vesting.

(4) See below for a reconciliation of Adjusted interest expense to Interest expense.

(5) Represents cash distributions declared for common and subordinated units outstanding as of each respective period. Amounts for 2018 reflect estimated cash distributions for common units outstanding for the quarter ended December 31, 2018.

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	Year Ended December 31,		
	2018	2017	2016
	(In millions)		
Reconciliation of Adjusted EBITDA to net cash provided by operating activities:			
Net cash provided by operating activities	$924	$834	$721
Interest expense, net of interest income	152	120	99
Net income attributable to noncontrolling interests	(2)	(1)	(1)
Current income taxes	—	2	(1)
Other non-cash items [(1)]	7	4	12
Proceeds from insurance	2	2	—
Changes in operating working capital which (provided) used cash:			
Accounts receivable	11	28	(4)
Accounts payable	(6)	(54)	40
Other, including changes in noncurrent assets and liabilities	5	12	(68)
Return of investment in equity method affiliate	7	5	15
Change in fair value of derivatives	(26)	(28)	60
Adjusted EBITDA	$1,074	$924	$873

(1) Other non-cash items includes amortization of debt expense, discount and premium on long-term debt and write-downs of materials and supplies.

	Year Ended December 31,		
	2018	2017	2016
	(In millions)		
Reconciliation of Adjusted interest expense to Interest expense:			
Interest Expense	$152	$120	$99
Amortization of premium on long-term debt	6	6	6
Capitalized interest on expansion capital	6	—	1
Amortization of debt expense and discount	(5)	(3)	(3)
Adjusted interest expense	$159	$123	$103

Liquidity and Capital Resources

The Partnership’s principal liquidity requirements are to finance its operations, fund capital expenditures and acquisitions, make cash distributions and satisfy any indebtedness obligations. We expect that our liquidity and capital resource needs will be met by cash on hand, operating cash flow, proceeds from commercial paper issuances, borrowings under our revolving credit facility, debt issuances and the issuance of equity. However, issuances of equity or debt in the capital markets and additional credit facilities may not be available to us on acceptable terms. Access to funds obtained through the equity or debt capital markets, particularly in the energy sector, has been constrained by a variety of market factors that have hindered the ability of energy companies to raise new capital or obtain financing at acceptable terms. Factors that contribute to our ability to raise capital through these channels depend on our financial condition, credit ratings and market conditions. Our ability to generate cash flow is subject to a number of factors, some of which are beyond our control. See Item 1A. “Risk Factors” for further discussion.

Working Capital

Working capital is the difference in our current assets and our current liabilities. Working capital is an indication of liquidity and potential need for short-term funding. The change in our 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, and the level and timing of spending for maintenance and expansion activity. As of December 31, 2018, we had a working capital deficit of $1,166 million. The deficit is primarily due to the $500 million 2019 Notes in short-term debt as well as $649 million

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of commercial paper outstanding as of December 31, 2018. We utilize our commercial paper program and revolving credit facility to manage the timing of cash flows and fund short-term working capital deficits.

Cash Flows

The following tables reflect cash flows for the applicable periods:

	Year Ended December 31,		
	2018	2017	2016
	(In millions)		
Net cash provided by operating activities	$924	$834	$721
Net cash used in investing activities	$(1,154)	$(706)	$(367)
Net cash provided by (used in) financing activities	$233	$(132)	$(335)

Operating Activities

The increase of $90 million, or 11%, in net cash provided by operating activities for the year ended December 31, 2018 as compared to the year ended December 31, 2017 is primarily due to an increase in net income of $86 million as a result of an increase in gathering and processing revenues, partially offset by an increase in cost of natural gas and natural gas liquids.

The increase of $113 million, or 16%, in net cash provided by operating activities for the year ended December 31, 2017 as compared to the year ended December 31, 2016 is primarily due to an increase in net income of $124 million as a result of an increase in gathering and processing revenues, partially offset by an increase in cost of natural gas and natural gas liquids.

Investing Activities

The increase of $448 million, or 63%, in net cash used in investing activities for the year ended December 31, 2018 as compared to the year ended December 31, 2017 was primarily due to higher capital expenditures of $457 million, including the $443 million acquisition of EOCS, net of cash received, in the fourth quarter of 2018. This increase is partially offset by an increase in proceeds from the sale of assets of $7 million and an increase in the return of investment in equity method affiliates of $2 million.

The increase of $339 million, or 92%, in net cash used in investing activities for the year ended December 31, 2017 as compared to the year ended December 31, 2016 was primarily due to higher capital expenditures of $331 million, including the $298 million acquisition of Align Midstream, LLC in 2017, as well as a decrease in return of investment of equity method affiliate of $10 million. These increases are partially offset by $2 million of proceeds received in 2017 from an insurance settlement.

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Financing Activities

Net cash provided by financing activities increased $365 million for the year ended December 31, 2018 as compared to the year ended December 31, 2017. Net cash used in financing activities decreased $203 million for the year ended December 31, 2017 as compared to the year ended December 31, 2016. Our primary financing activities consist of the following:

	Year Ended December 31,		
	2018	2017	2016
	(In millions)		
Net proceeds (repayments) of Revolving Credit Facility	$250	$(636)	$326
Increase (decrease) in short-term debt	244	405	(236)
Proceeds from 2028 Notes, net of issuance costs	787	—	—
Proceeds from 2027 Notes, net of issuance costs	—	691	—
Proceeds from issuance of Series A Preferred Units, net of issuance costs	—	—	362
Proceeds from issuance of common units	2	—	137
Repayment of notes payable—affiliated companies	—	—	(363)
Repayment of 2015 Term Loan Agreement	(450)	—	—
Distributions	(591)	(590)	(561)
Cash paid for employee equity-based compensation	(9)	(2)	—

Sources of Liquidity

As of December 31, 2018, our sources of liquidity included:

- cash on hand;
- cash generated from operations;
- proceeds from commercial paper issuances and borrowings under our Revolving Credit facility; and
- capital raised through debt and equity markets.

Please see Note 6. “Enable Midstream Partners, LP Partners’ Equity” and Note 11. “Debt” in the Notes to the Consolidated Financial Statements under Item 8. “Financial Statements and Supplementary Data” for cash distributions to common and subordinated unitholders and a description of the Partnership’s debt agreements.

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 sold an aggregate of 18,500 common units under the ATM Program, which generated proceeds of approximately $303,000 (net of approximately $3,000 commissions). The Partnership incurred approximately $345,000 of expenses associated with the filing of the registration statements for the ATM Program. 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.

Distribution Reinvestment Plan

In June 2016, the Partnership implemented a Distribution Reinvestment Plan (DRIP), which, beginning with the quarterly distribution for the quarter ended September 30, 2016, offers owners of our common units the ability to purchase additional common units by reinvesting all or a portion of the cash distributions paid to them on their common units. The Partnership will have the sole discretion to determine whether common units purchased under the DRIP will come from our newly issued common units or from common units purchased on the open market. The purchase price for newly issued common units will be the average of the high and low trading prices of the common units on the New York Stock Exchange-Composite Transactions for the five

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trading days immediately preceding the investment date. The purchase price for common units purchased on the open market will be the weighted average price of all common units purchased for the DRIP for the respective investment date. We can set a discount ranging from 0% to 5% for common units purchased pursuant to the DRIP. The discount is currently set at 0%. Participation in the DRIP is voluntary, and once enrolled, our unitholders may terminate participation at any time. The Partnership has had minimal participation in the DRIP since its inception in June 2016 and, on July 31, 2018, the Partnership suspended the DRIP.

Capital Requirements

The midstream business is capital intensive and can require significant investment to maintain and upgrade existing operations, connect new wells to the system, organically grow into new areas and comply with environmental and safety regulations. Going forward, our capital requirements will consist of the following:

- maintenance capital expenditures, which are cash expenditures (including expenditures for the construction or development of new capital assets or the replacement, improvement or expansion of existing capital assets) made to maintain, over the long-term, our operating capacity or operating income; and
- expansion capital expenditures, which are cash expenditures incurred for acquisitions or capital improvements that we expect will increase our operating income or operating capacity over the long term.

For the year ending December 31, 2019, we estimate that expansion capital could range from approximately $325 million to $425 million and our maintenance capital could range from approximately $105 million to $125 million. Our future expansion capital expenditures may vary significantly from period to period based on commodity prices and the investment opportunities available to us. We expect to fund future capital expenditures from cash flow generated from our operations, issuances of commercial paper, borrowings under our Revolving Credit Facility, new debt offerings or the issuance of additional partnership units. Issuances of equity or debt in the capital markets may not, however, be available to us on acceptable terms.

Distributions of Available Cash

General

Our Partnership Agreement requires that, within 60 days after the end of each quarter, we distribute all of our Available Cash (defined below) to unitholders of record on the applicable record date.

Definition of Available Cash

Available cash is defined in our Partnership Agreement, which is an exhibit to this Annual Report on Form 10-K. Available cash generally means, for any quarter, all cash and cash equivalents on hand at the end of that quarter:

- less, the amount of cash reserves established by our general partner to:
- provide for the proper conduct of our business (including cash reserves for our future capital expenditures, future acquisitions and anticipated future debt service requirements and refunds of collected rates reasonably likely to be refunded as a result of a settlement or hearing related to FERC rate proceedings or rate proceedings under applicable law subsequent to that quarter);
- comply with applicable law, any of our debt instruments or other agreements;
- provide funds for distributions to our unitholders and to our general partner for any one or more of the next four quarters (provided that our general partner may not establish cash reserves for distributions if the effect of the establishment of such reserves will prevent us from distributing the minimum quarterly distribution on all common units and any cumulative arrearages on such common units for the current quarter); or
- provide funds for distributions on our preferred units;
- plus, if our general partner so determines, all or any portion of the cash on hand on the date of determination of available cash for the quarter resulting from working capital borrowings made subsequent to the end of such quarter.

Minimum Quarterly Distribution

The Minimum Quarterly Distribution, as set forth in the Partnership Agreement, is $0.2875 per unit per quarter, or $1.15 per unit on an annualized basis to the extent we have sufficient cash from our operations after the establishment of cash reserves and the payment of costs and expenses, including reimbursements of expenses to our general partner. Our current quarterly distribution is $0.318 per unit, or $1.272 per unit annualized. However, there is no guarantee that we will pay the minimum quarterly distribution on our units in any quarter. Even if our cash distribution policy is not modified or revoked, the amount of distributions paid under

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our policy and the decision to make any distribution is determined by our general partner, taking into consideration the terms of our Partnership Agreement. Please read "—Liquidity and Capital Resources" for a discussion of the restrictions included in our credit agreement that may restrict our ability to make distributions.

Percentage Allocations of Available Cash from Operating Surplus

The following table illustrates the percentage allocations of available cash from operating surplus between the unitholders and our general partner (through the incentive distribution rights) based on the specified target distribution levels. The amounts set forth under "Marginal Percentage Interest in Distributions" are the percentage interests of our general partner and the unitholders in any available cash from operating surplus we distribute up to and including the corresponding amount in the column "Total Quarterly Distribution Per Unit Target Amount." The percentage interests shown for our unitholders for the minimum quarterly distribution are also applicable to quarterly distribution amounts that are less than the minimum quarterly distribution. The percentage interests set forth below for our general partner assume that our general partner has not transferred its incentive distribution rights and that there are no arrearages on common units.

	Total Quarterly Distribution Per Unit Target Amount	Marginal Percentage Interest in Distributions	
		Unitholders	General Partner
Minimum Quarterly Distribution	$0.2875	100.0 %	— %
First Target Distribution	up to $0.330625	100.0 %	— %
Second Target Distribution	above $0.330625 up to $0.359375	85.0 %	15.0 %
Third Target Distribution	above $0.359375 up to $0.431250	75.0 %	25.0 %
Thereafter	above $0.431250	50.0 %	50.0 %

In determining the amount of available cash for distributions to holders of common units, the Board of Directors determines the amount of cash reserves to set aside for our operations, including reserves for future working capital, maintenance capital expenditures, expansion capital expenditures, acquisitions and other matters, which will impact the amount of cash we are able to distribute to our unitholders. However, we expect that we will rely primarily upon external financing sources, including borrowings under our Revolving Credit Facility and issuances of debt and equity securities, as well as cash reserves, to fund our expansion capital expenditures including acquisitions. To the extent we are unable to finance growth externally and are unwilling to establish cash reserves to fund future expansions, our available cash for distributions will not significantly increase. In addition, because we distribute all of our available cash, we may not grow as quickly as businesses that reinvest their available cash to expand ongoing operations. To the extent we issue additional units in connection with any expansion capital expenditures including acquisitions, or to the extent we issue additional units ranking senior to our common units, the payment of distributions on those additional units may increase the risk that we will be unable to maintain or increase our per unit distribution level. There are no limitations in our Partnership Agreement or in the terms of our Revolving Credit Facility on our ability to issue additional units, including units ranking senior to the common units.

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We paid or have authorized payment of the following cash distributions to common and subordinated unitholders, as applicable, during the years ended December 31, 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

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(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 unitholders of record at the close of business on February 19, 2019.

On February 18, 2016, we completed the private placement of 14,520,000 Series A Preferred Units. 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%. The Series A Preferred Units rank senior to the Partnership's common units with respect to the payment of distributions and, unless full distributions are paid on the Series A Preferred Units with respect to a quarter, we cannot declare or pay a distribution on common units with respect to that quarter. We intend to pay full distributions on Series A Preferred Units each quarter, however these distributions are not mandatory, and we do not have a legal obligation to pay these distributions. For more information on our Series A Preferred Units, see Note 6. "Enable Midstream Partners, LP Partners' Equity" included in Item 8. "Financial Statements and Supplementary Data—Notes to the Consolidated Financial Statements."

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We paid or have authorized payment of the following cash distributions to holders of the Series A Preferred Units during the years ended December 31, 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 a $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.

Contractual Obligations

In the ordinary course of business, we enter into various contractual obligations for varying terms and amounts. The following table includes our contractual obligations and other commitments as of December 31, 2018 and our best estimate of the period in which the obligation will be settled:

	2019	2020-2021	2022-2023	After 2023	Total
Maturities of short-term debt	$649	$ —	$ —	$—	$649
Maturities of long-term debt (1)(2)	500	250	250	2,650	3,650
Noncancellable operating leases	14	6	6	14	40
Total contractual obligations	$1,163	$ 256	$ 256	$2,664	$4,339

(1) Contractual interest payments associated with long-term debt are $143 million, $250 million, $243 million and $861 million in 2019, 2020 through 2021, 2022 through 2023 and after 2023, respectively.

(2) Excludes premium (discount) on long-term debt of $1 million.

Off-Balance Sheet Arrangements

We do not have any off-balance sheet arrangements.

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Critical Accounting Policies and Estimates

Our financial statements and the related notes thereto contain information that is pertinent to Management's Discussion and Analysis. In preparing our 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 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 Partnership's financial statements. However, the Partnership believes it has taken reasonable, but conservative, positions where assumptions and estimates are used in order to minimize the negative financial impact to the Partnership that could result if actual results vary from the assumptions and estimates. In management's opinion, the areas of the Partnership where the most significant judgment is exercised for all Partnership segments includes the determination of impairment estimates of long-lived assets (including intangible assets) and goodwill, revenue recognition, valuation of assets and depreciable lives of property, plant and equipment and amortization methodologies related to intangible assets. The selection, application and disclosure of the following critical accounting estimates have been discussed with the Partnership's board of directors. The Partnership discusses its significant accounting policies, including those that do not require management to make difficult, subjective, or complex judgments or estimates, in Note 1 of the Notes to the Consolidated Financial Statements.

Impairment of Long-lived Assets (including Intangible Assets)

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. During the year ended December 31, 2016, the Partnership recorded an impairment of $9 million on the Service Star business line, a component of our gathering and processing segment. The Partnership recorded no other material impairments to long-lived assets in the years ended December 31, 2018, 2017 or 2016. 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.

Impairment of Goodwill

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.

Because quoted market prices for the Partnership’s reporting units are not available, management must apply judgment in determining the estimated fair value of reporting units for purposes of performing the goodwill impairment test, when necessary. Management considered observable transactions in the market, as well as trading multiples and cost of capital for peers, to determine appropriate multiples and discount rates to apply against historical and forecasted cash flows. A lower fair value estimate in the future for any of the Partnership’s reporting units could result in a goodwill impairment. Factors that could trigger a lower fair value estimate include sustained price declines, throughput declines, contracted capacity declines, cost increases, regulatory or political environment changes and other changes in market conditions such as decreased prices in market-based transactions for similar assets.

As of December 31, 2016, the Partnership had no goodwill recognized on its Consolidated Balance Sheet. During the fourth quarter of the year ended December 31, 2017, the Partnership recognized $12 million of goodwill related to the acquisition of Align. During the fourth quarter of 2018, as a result of the acquisition of EOCS, the Partnership recorded $86 million of goodwill. All goodwill is included in the gathering and processing reportable segment.

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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 each of December 31, 2018 and 2017, respectively.

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 ASU No. 2014-09, "Revenue from Contracts with Customers (Topic 606).

Valuation of Assets

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

In the years ended December 31, 2018 and 2017, the Partnership completed acquisitions accounted for as business combinations as discussed in Note 4 of the Notes to the Consolidated Financial Statements. As part of these acquisitions, the Partnership engaged the services of third-party valuation specialists to assist it in determining the fair value of the acquired assets and liabilities, including goodwill; however, the ultimate determination of those values is the responsibility of the Partnership's management. The Partnership bases its estimates on assumptions believed to be reasonable, but which are inherently uncertain. These valuations require the use of management's assumptions, which would not reflect unanticipated events and circumstances that may occur.

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

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

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

We are exposed to various market risks, including volatility in commodity prices and interest rates.

Commodity Price Risk

While we generate a substantial portion of our gross margin pursuant to fee-based contracts that include minimum volume commitments and/or demand fees, we are also directly and indirectly exposed to changes in the prices of natural gas, condensate and NGLs. The Partnership utilizes derivatives and forward commodity sales to mitigate the effects of price changes. We do not enter into risk management contracts for speculative purposes. For further information regarding our derivatives, see Note 12 of the Notes to Consolidated Financial Statements in Part II, Item 8. “Financial Statements and Supplementary Data.”

Based on our forecasted volumes, prices and contractual arrangements, we estimate approximately 12% of our total gross margin for the twelve months ending December 31, 2019 will be directly exposed to changes in commodity prices, excluding the impact of hedges and contractual floors related to commodity prices in certain agreements. Since December 31, 2018, we have entered into additional derivative contracts to further manage our exposure to commodity price risk for the twelve months ending December 31, 2019.

Commodity price risk is estimated as the potential loss in value resulting from a hypothetical 10% decline in prices over the next 12 months. Based on a sensitivity analysis, a 10% decrease in prices from forecasted levels would decrease net income by approximately $15 million for natural gas and ethane and $9 million for NGLs (other than ethane) and condensate, excluding the impact of hedges for the twelve months ending December 31, 2019.

Interest Rate Risk

Our current interest rate risk exposure is related primarily to our debt portfolio. The majority of our debt portfolio is comprised of fixed rate debt, which mitigates the impact of fluctuations in interest rates. Future issuances of long-term debt could be impacted by increases in interest rates, which could result in higher interest costs. Borrowings under our Revolving Credit Facility and any issuances under our commercial paper program could be at a variable interest rate and could expose us to the risk of increasing interest rates. Based upon the $899 million outstanding borrowings under the Revolving Credit Facility and commercial paper program as of December 31, 2018, and holding all other variables constant, a 100 basis-point, or 1%, increase in interest rates would increase our annual interest expense by approximately $9 million.

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Item 8. Financial Statements and Supplementary Data

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.

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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

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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
	7,218	7,280

Common units (433,232,411 issued and outstanding at December 31, 2018 and 432,584,080 issued and outstanding at December 31, 2017, respectively)		
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

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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)	(1,830)	(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

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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

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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.

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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.

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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.

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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

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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.

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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

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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.

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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

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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.

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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.
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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

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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.

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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.

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(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

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

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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):

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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.

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(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

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(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

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(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.

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

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(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,

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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.

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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.

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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:

		December 31, 2018		December 31, 2017	
		Fair Value			
Instrument	Balance Sheet Location	Assets	Liabilities	Assets	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:

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	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.

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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.

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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