UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 10-K

☒ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended December 31, 2019

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 other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
499 West Sheridan Avenue, Suite 1500 Oklahoma City, Oklahoma	**73102**
(Address of principal executive offices)	(Zip Code)

(405) 525-7788
Registrant's telephone number, including area code

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

Title of each class	Trading symbol(s)	Name of each exchange on which registered
Common Units Representing Limited Partner Interests	**ENBL**	**New York Stock Exchange**

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

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

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or 15(d) of the Act. ☐ Yes ☒ No

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.

☒ Yes ☐ No

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit such files). ☒ Yes ☐ No

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

Large accelerated filer	☒	Accelerated filer	☐
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 ☒ No

The aggregate market value of the Common Units held by non-affiliates of the registrant, based upon the closing price of $13.71 per common unit on June 28, 2019, was approximately $1.2 billion.

As of January 31, 2020, there were 435,206,963 common units outstanding.

DOCUMENTS INCORPORATED BY REFERENCE
None

ENABLE MIDSTREAM PARTNERS, LP
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GLOSSARY

2019 Notes.	$500 million aggregate principal amount of the Partnership’s 2.400% senior notes due 2019.
2019 Term Loan Agreement.	Unsecured term loan agreement dated January 29, 2019, by and among Enable Midstream Partners, LP and Bank of America, N.A., as administrative agent, and the several lenders from time to time party thereto.
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.
2029 Notes.	$550 million aggregate principal amount of the Partnership’s 4.150% senior notes due 2029.
2044 Notes.	$550 million aggregate principal amount of the Partnership’s 5.000% senior notes due 2044.
ADIT.	Accumulated Deferred Income Taxes.
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.
ASC.	Accounting Standards Codification.
ASU.	Accounting Standards Update.
Atoka.	Atoka Midstream LLC, in which the Partnership owns a 50% interest as of December 31, 2019, which provides gathering and processing services to a customer 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.
EGR.	Enable Gulf Run Transmission, LLC, a wholly owned subsidiary of the Partnership.

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, 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 to customers 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 2,300-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.
ESCP.	Enable South Central Pipeline, LLC, formerly Velocity Pipeline Partners, LLC, 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.
ETGP.	Enable Texola Gathering & Processing, LLC, formerly Align Midstream, LLC, a wholly owned subsidiary of the Partnership that provides natural gas gathering and processing services to customers in the Cotton Valley and Haynesville plays of the Ark-La-Tex Basin in Texas.
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, 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.
Moody's	Moody's Investor Services.
MOP.	Maximum operating pressure for hazardous liquid pipelines.
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 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.
PVI.	Preventable Vehicle Incidents.
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.
S&P.	Standard & Poor's Rating Services.
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, 2019, 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.
TRI.	Total Recordable Incidents.
WOTUS.	Waters of the United States.
WTI.	West Texas Intermediate.
Wynnewood Refinery.	A refinery owned by CVR Energy, Inc. and connected to the ESCP system.

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,” “plan,” “estimate,” “anticipate,” “believe,” “project,” “budget,” “potential,” or “continue,” and similar expressions are used to identify forward-looking 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.

PART I

Item 1. Business

Overview

Enable Midstream Partners, LP is a Delaware limited partnership formed in May 2013 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 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 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, 2019, our portfolio of midstream energy infrastructure assets primarily included:

- approximately 14,000 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 and Asset Optimization Opportunities Associated with Our Strategically Located Assets:* We own and operate assets servicing four major producing basins and key natural gas and crude oil demand centers in the United States. We intend to grow our business by utilizing a disciplined approach emphasizing capital efficiency when operating our existing assets and 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 build and maintain relationships with key customers both on the supply and demand sides of the natural gas and crude oil value chain, in an effort to attract new volumes and to expand our asset footprint and business lines.
- *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

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, 2019, CenterPoint Energy owned 53.7% of our common units and 100% of our Series A Preferred Units, and OGE Energy owned 25.5% of our common units. In addition, our sponsors own Enable GP, our general partner. As of December 31, 2019, 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, distribution and power generation facilities, own and operate natural gas distribution facilities, and supply natural gas to commercial, industrial and utility customers. 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, 2019, approximately 2% 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, 2019, approximately 5% of our 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.

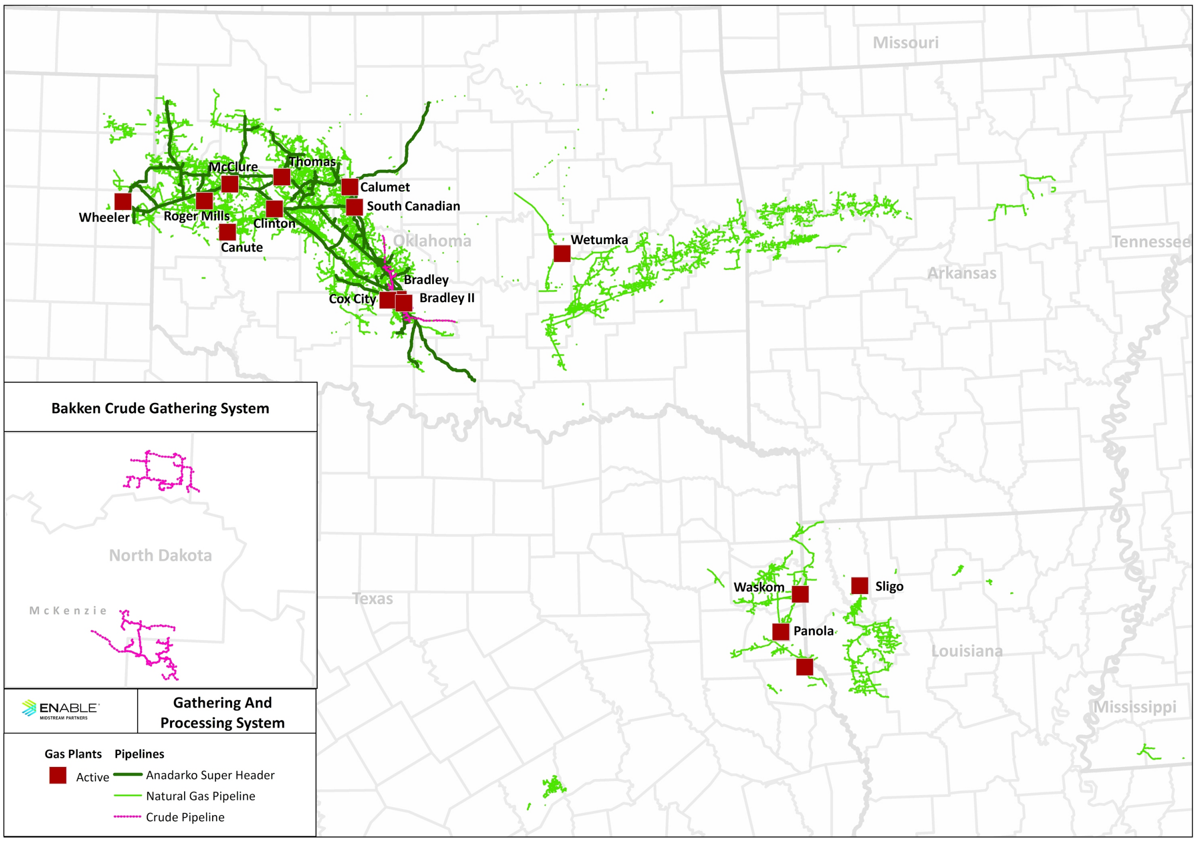
Our Assets and Operations

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 gathering assets serving the Williston Basin. We provide a variety of services to the active producers in 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, 2019, we served approximately 210 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, 2019, we served approximately 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, 2019, we served approximately 90 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 plays (including the area where the SCOOP and STACK come together known as the Merge play). As of December 31, 2019, our customers included five producers and one refinery.

- *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, 2019:

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]	8,700	889,700	2.34	11	1,845	113.20
Arkoma Basin	3,000	139,800	0.47	1	60	5.42
Ark-La-Tex Basin [3]	1,800	158,400	1.75	3	645	9.96
Total	13,500	1,187,900	4.56	15	2,550	128.58

(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.

The following table sets forth information with respect to our natural gas processing plants as of or for the year ended December 31, 2019:

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	151	200	28,000
Bradley	2015	Cryogenic	184	200	28,000
McClure	2013	Cryogenic	206	200	22,000
Wheeler	2012	Cryogenic	137	200	22,000
South Canadian	2011	Cryogenic	194	200	26,000
Clinton	2009	Cryogenic	111	120	14,000
Roger Mills	2008	Refrigeration	26	100	—
Canute	1996	Cryogenic	29	60	4,300
Cox City	1994	Cryogenic	138	180	14,500
Thomas	1981	Cryogenic	99	135	9,900
Calumet	1969	Lean Oil	138	250	8,000
Arkoma					
Wetumka	1983	Cryogenic	43	60	5,000
Ark-La-Tex					
Panola	2007	Cryogenic	47	100	8,000
Sligo [3]	2004	Refrigeration	20	225	1,400
Waskom	1995 [4]	Cryogenic	247	320	14,500
Total			1,770	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 20 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, El Paso Natural Gas, ETC Tiger, Gulf South, Natural Gas Pipeline of America, 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.

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, 2019:

Asset/Basin	**Approximate Length (miles)**	**Design Capacity (MBbls/d)**	**Average Throughput Volume (MBbls/d)**
Anadarko Basin crude oil and condensate	175	275	92.70
Williston Basin crude oil	175	58	35.76
Williston Basin produced water	150	19	13.95
Total	500	352	142.41

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). A portion of our operations are conducted through ESCP, a joint venture with a subsidiary of CVR Energy, Inc., which is operated by us and in which we own a 60% membership interest. 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 Energy, Inc. refinery located at Wynnewood, Oklahoma (the Wynnewood Refinery). For the year ended December 31, 2019, 54% of crude oil and condensate gathered on the system was delivered to 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 those 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 delivered to our interconnections, which can be further delivered 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 delivered to our interconnection, which can be further delivered to the Enbridge North Dakota Pipeline and the Dakota Access Pipeline.

Natural Gas Gathering and Processing Customers. For the year ended December 31, 2019, our top natural gas gathering and processing customers by gathered volumes were Continental Resources, Inc. (Continental), Vine Oil & Gas LP (Vine), GeoSouthern Energy Corporation (GeoSouthern), XTO, Tapstone Energy LLC (Tapstone), Rockcliff Energy LLC (Rockcliff), BP America Production Company (BP), Ovintiv Inc. (Ovintiv), Marathon Oil Corporation (Marathon Oil) and FourPoint Energy, LLC (FourPoint). For the year ended December 31, 2019, our top ten natural gas producer customers accounted for approximately 68% 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 Energy, Inc. Our Anadarko Basin crude oil and condensate gathering systems are intrastate pipeline systems, 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, less the value of the percentage of NGLs retained on our own account, from the producer, return the processed natural gas to the producer and sell the NGLs for our own account.

- Under a typical percent-of-proceeds processing arrangement, we process the raw natural gas to extract the NGLs, purchase the NGLs, less the value of the percentage of natural gas and NGLs retained on our own account, return the remaining percentage of 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, 2019, 70%, 26% and 4% 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, 2019, 80% of our gathering and processing gross margin was fee-based, and the remaining 20% 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. As of December 31, 2019, 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	4%	6%	11%	1%	22%
Percentage attributable to shortfall payments (1)	5%	83%	19%	—%	33%
Natural gas volume commitment-weighted average remaining contract term (in years) (3)	7.4	4.7	0.5	—	3.3
Crude oil and condensate volume commitment-weighted average remaining contract term (in years) (3)	—	—	—	9.2	9.2

(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.
(3) Weighted-average is based upon volumes for the year ended December 31, 2019.

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, 2019, 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)	5.0	1.7	1.2	0.3	8.2
Natural gas volume-weighted average remaining contract term (in years)	5.4	1.8	3.8	—	4.3
Crude oil and condensate volume-weighted average remaining contract term (in years)	12.6	—	—	10.4	11.8

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, 2019, we constructed 100 miles of gathering pipelines, added 27,100 horsepower of compression and invested $314 million in the construction of gathering and processing assets, which primarily included well connections to our gathering system. 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 2021.

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. Competition for crude oil, condensate, produced water and extracted NGL services also includes trucking and railroad transportation companies. 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.

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, 2019:

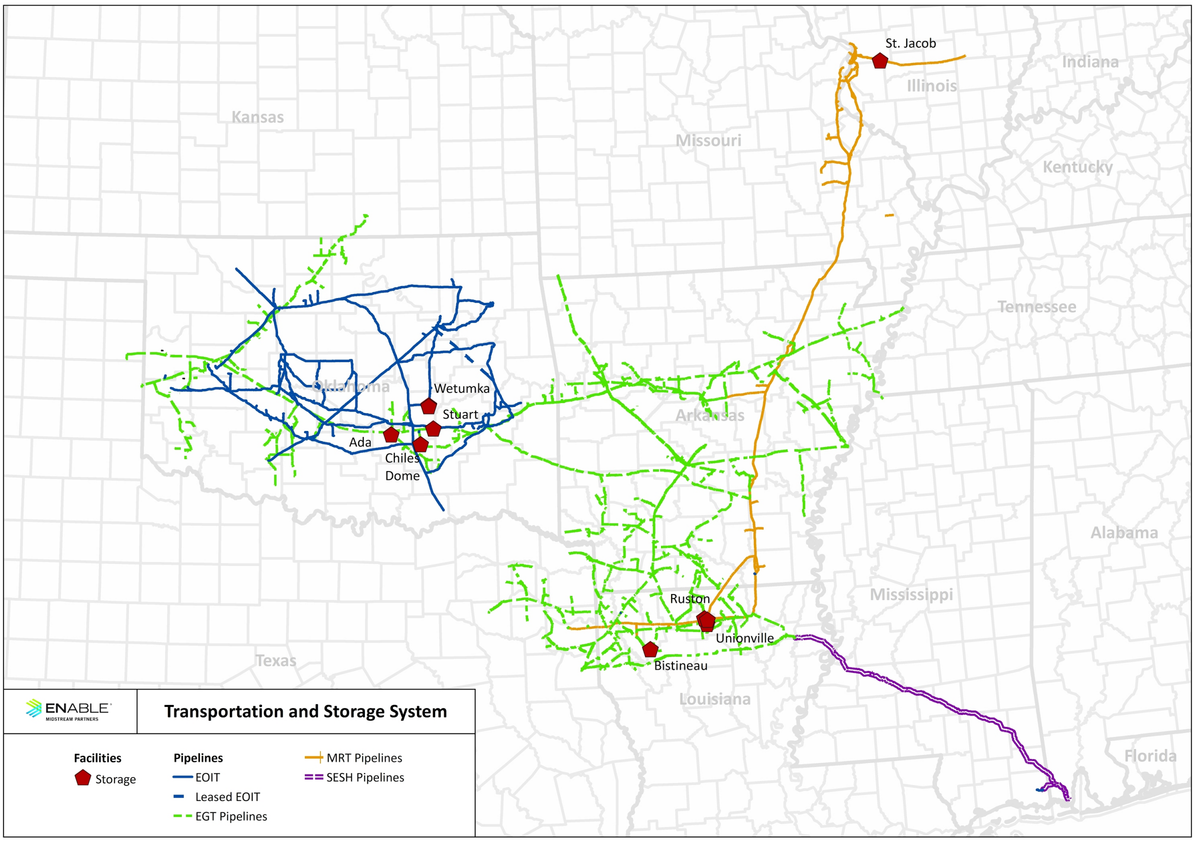
Transportation and Storage							
Asset	Length (miles)	Compression (Horsepower)	Average Throughput (TBtu/d)	Transportation Capacity (Bcf/d) (1)	Transportation Firm Contracted Capacity (Bcf/d) (2)	Storage Capacity (Bcf)	Storage Firm Contracted Capacity (Bcf/d)
EGT	5,900	391,300	3.24	6.3	4.73	29.0	22.92
MRT	1,600	119,700	0.80	1.7	1.58	31.5	24.41
EOIT	2,300	218,800	2.14 (3)	— (3)	—	24.0	10.08
Subtotal	9,800	729,800	6.18	8.0	6.31	84.5	57.41
SESH	290	107,800	— (5)	— (4)	— (5)	— (5)	— (5)
Total	10,090	837,600	6.18	8.0	6.31	84.5	57.41

(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, 2019, the peak daily throughput was 2.3 TBtu/d or, on a volumetric basis, 2.3 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.

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, 2019, our top transportation and storage customers by revenue were affiliates of CenterPoint Energy, Spire Inc. (Spire), OGE Energy, American Electric Power Co. (AEP), Continental, Chesapeake Energy Corp., Midcontinent Express Pipeline LLC (MEP), Ovintiv, Entergy Corporation (Entergy) and BP PLC (BP).

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, 2019, we invested $46 million in the construction of transportation pipelines, including the acquisition of right-of-way related to the Gulf Run Pipeline project, and a connection to an additional power plant to the EOIT system. In September 2018, we executed a precedent agreement for 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. On January 30, 2019, a final investment decision was made by Golden Pass LNG, the cornerstone shipper for the LNG facility to be served by the Gulf Run Pipeline project. Subject to approval of the project by FERC, the Partnership will be required to construct a large-diameter pipeline from northern Louisiana to Gulf Coast markets. In addition, the Partnership may transfer existing EGT transportation infrastructure to the Gulf Run Pipeline. Under the precedent agreement, the Partnership estimates the cost to complete the Gulf Run Pipeline project to serve Golden Pass LNG would be as much as $500 million and the project is backed by a 20-year firm transportation service agreement for 1.1 Bcf/d. The Partnership anticipates filing a certificate application with FERC to obtain authorization to construct and operate the pipeline in the first half of 2020. The project scope filed for in the application is expected to provide for approximately 1.7 Bcf/d of capacity, which would both accommodate Golden Pass LNG's 1.1 Bcf/d commitment and allow for additional capacity subscriptions that may develop from ongoing discussions, at an estimated cost of approximately $640 million, which excludes amounts related to allowance for funds used during construction. Ultimately, the project will be sized to meet contracted customer capacity commitments. The project is expected to be placed into service in 2022.

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, 2019, provide a combined capacity of 84.5 Bcf with 2.0 Bcf/d of aggregate maximum withdrawal capacity from our eight storage facilities in Oklahoma, Louisiana and Illinois, which includes 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. On September 23, 2019, the Partnership entered into an agreement to sell its undivided 1/12th interest in the Bistineau Storage Facility. Until such time as the sale closes, the Partnership will continue to utilize this facility to provide storage services to its customers. On January 27, 2020, FERC approved the sale. The Partnership anticipates closing the sale on April 1, 2020. See Note 17 of the Notes to Consolidated Financial Statements in Part II, Item 8. "Financial Statements and Supplementary Data" for further discussion.



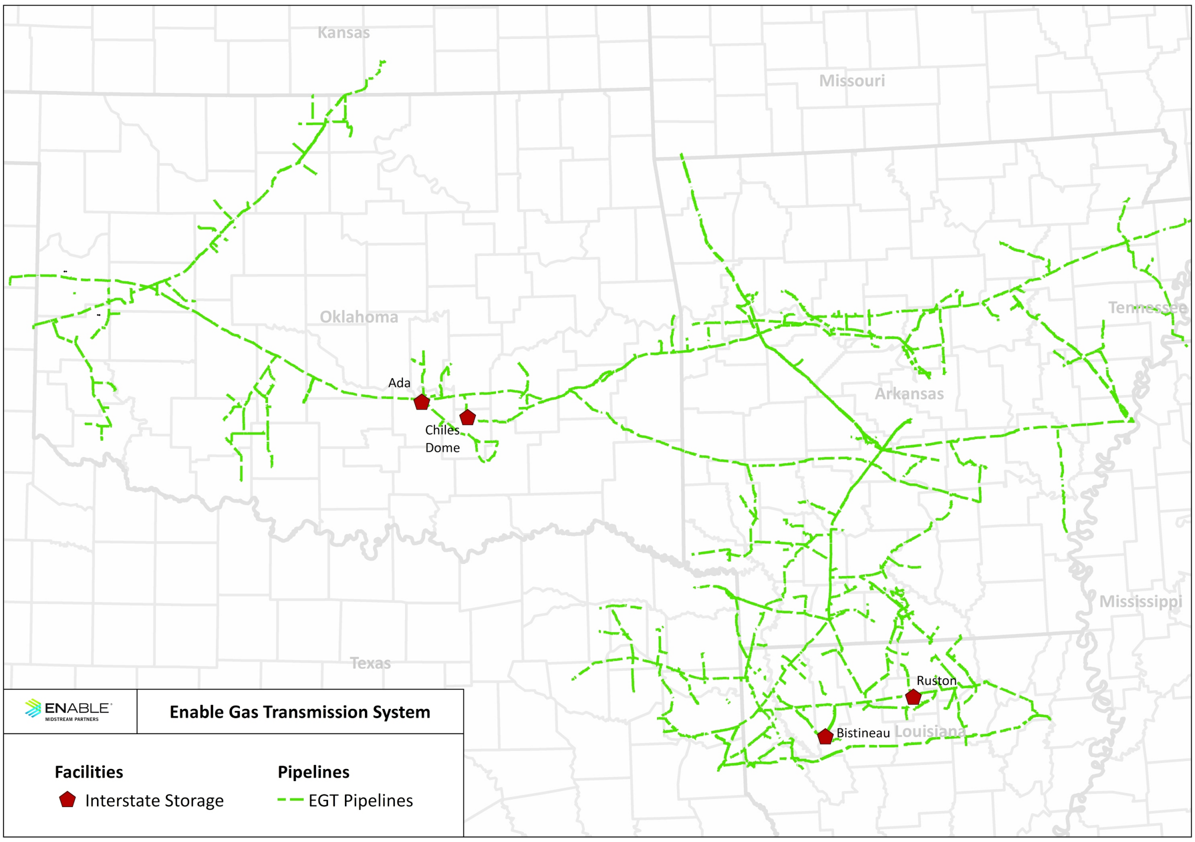
Our transportation and storage assets are comprised of three categories: (1) interstate transportation and storage, (2) intrastate transportation and storage and (3) our investment in SESH.

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 6.3 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, 2019, 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 the 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, 2019, approximately 26% of EGT's service revenues were attributable to contracts with LDCs owned by CenterPoint Energy. As of December 31, 2019, contracts with LDCs owned by CenterPoint Energy had a volume-weighted average remaining contract life of 1.2 years for transportation and 1.2 years for storage. In addition to CenterPoint Energy's LDCs, EGT's other major customers include Continental and AEP.

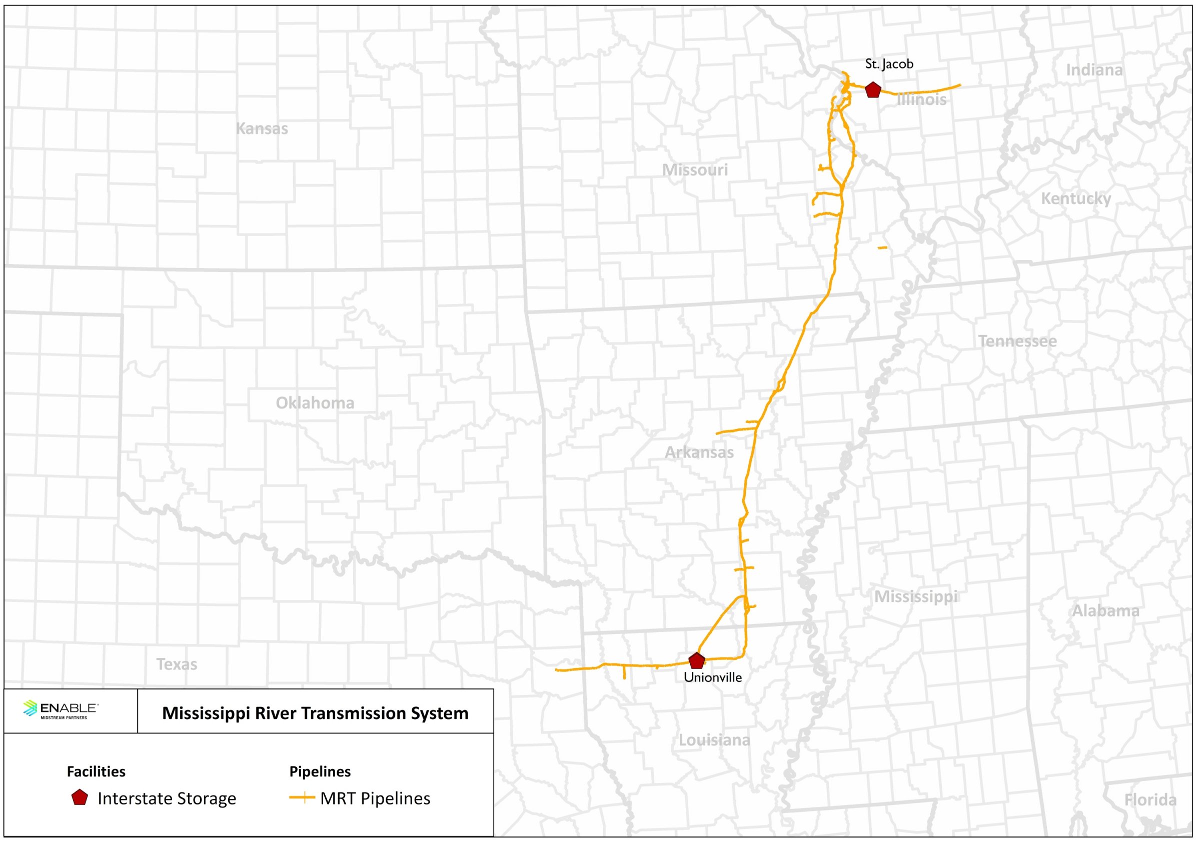
Contracts. Although EGT has established maximum rates for interstate transportation and storage services as required by FERC, EGT is authorized to enter into negotiated rate and discounted rate agreements with its customers. EGT's services are typically provided under firm, fee-based transportation and storage agreements. For the year ended December 31, 2019, approximately 59% of our transportation and storage gross margin was derived from EGT's firm contracts, 75% of EGT's transportation capacity was under firm contracts and 79% of EGT's storage capacity was under firm contracts. EGT's transportation capacity under firm contracts had a volume-weighted average remaining contract life of 2.8 years and EGT's storage capacity under firm contracts had a volume-weighted average remaining contract life of 1.3 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 received the required regulatory approvals to extend transportation and storage services with EGT. The term for the transportation and storage services provided to CenterPoint Energy's LDCs in Arkansas, Louisiana, Oklahoma and Northeast Texas is expected to 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 underground natural gas storage facilities 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, 2019, operate at a combined capacity of 31.5 Bcf with 590 MMcf/d of aggregate maximum withdrawal capacity.



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, 2019, 70% of MRT's service revenues were attributable to contracts with Spire. As of December 31, 2019, contracts with Spire had a volume-weighted average remaining contract life of 5.1 years for transportation and 4.4 years for storage, which are subject to FERC rate case approval. MRT's other customers include utilities and industrial end users. MRT's customers are primarily located in Arkansas, Missouri and Illinois.

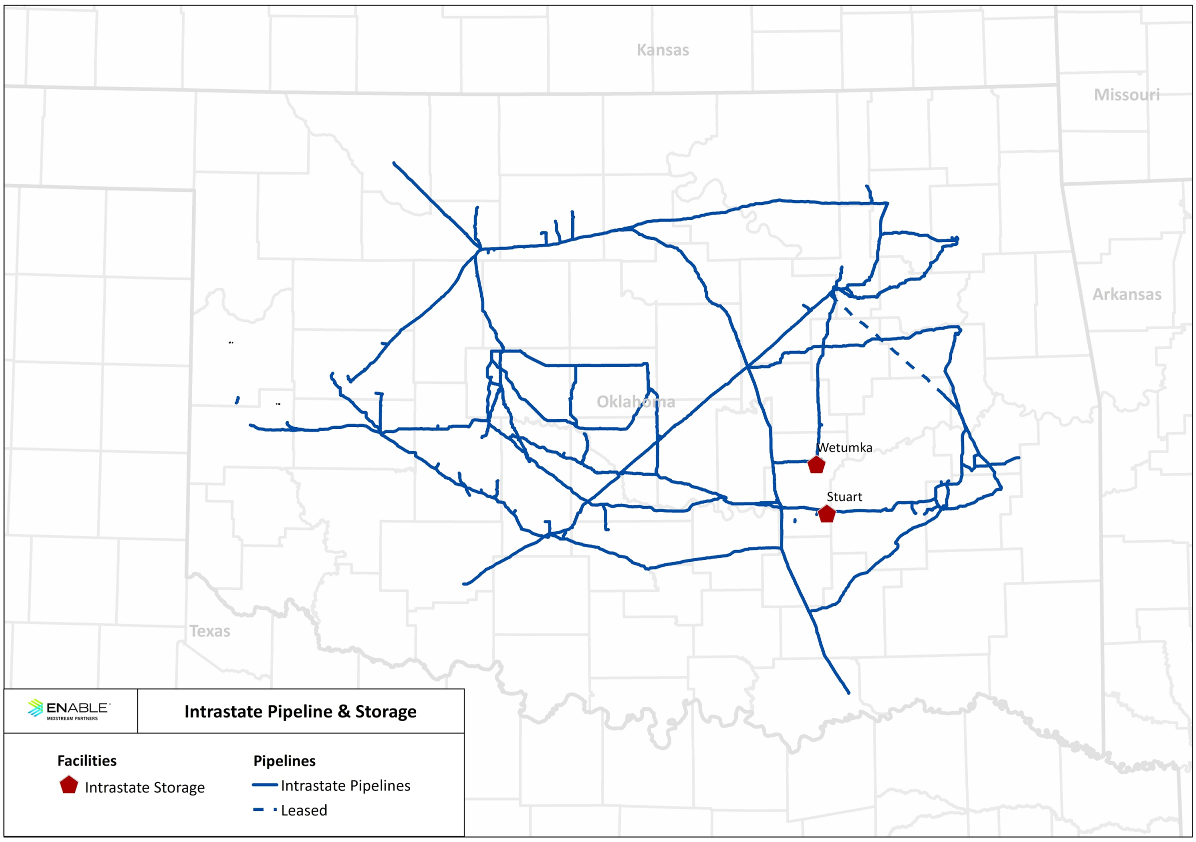
Contracts. MRT's services are typically provided under firm, fee-based transportation and storage agreements, with rates and terms of service regulated by FERC. For the year ended December 31, 2019, approximately 11% of our transportation and storage gross margin was derived from MRT's firm contracts, 77% of MRT's transportation capacity was under firm contracts and 93% of MRT's storage capacity was under firm contracts. As of December 31, 2019, MRT's transportation capacity under firm contracts had a volume-weighted average remaining contract life of 4.8 years and MRT's storage capacity under firm contracts had a volume-weighted average remaining contract life of 4.3 years, which are subject to FERC rate case approval. MRT's firm transportation contracts representing 64%, 24% and 12% of Spire's firm transportation capacity are scheduled to expire in July 2024, October 2025 and March 2026, respectively. All of Spire's firm storage contracts are scheduled to expire in May 2021, which are subject to FERC rate case approval.

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 has switched a portion of demand to its affiliate, the interstate Spire STL Pipeline. 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 2.14 TBtu/d of average daily throughput for the year ended December 31, 2019. In addition to 2,300 miles of intrastate pipelines, EOIT has two underground natural gas storage facilities in Oklahoma, which, as of December 31, 2019 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 and ONEOK Western Trails Pipeline, L.L.C. In addition, EOIT connects to 46 end-user customers, including 15 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, 2019, approximately 7% of our 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 extends 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 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.

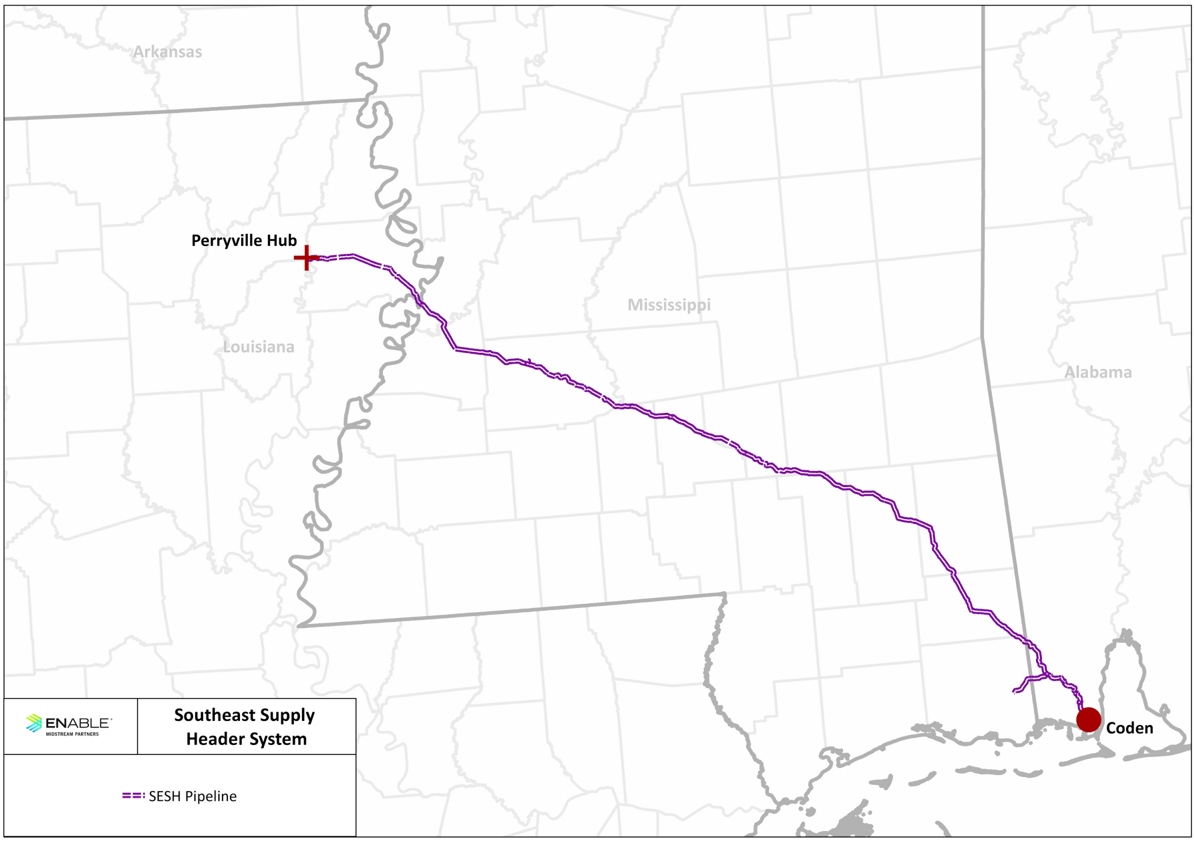
Contracts. EOIT provides fee-based firm and interruptible transportation and storage services on both an intrastate basis and, pursuant to Section 311 of the NGPA, on an interstate basis. For the year ended December 31, 2019, approximately 23% of our transportation and storage gross margin was derived from EOIT's firm contracts. EOIT's transportation capacity was under firm contracts with a volume-weighted average remaining contract life of 6.9 years and EOIT's storage capacity was under firm contracts with a volume-weighted average remaining contract life of 0.8 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.

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, 2019, SESH operates at 1.09 Bcf/d of transportation capacity from the Perryville Hub in Louisiana to its endpoint in Mobile County, Alabama.



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. For the year ended December 31, 2019, SESH's transportation contracts have a volume-weighted average remaining contract life of 2.8 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.

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 with 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 and is not a true-up or tracker of money owed shippers.

Included in the issuances on March 15, 2018, was 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 required 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 would 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. EGT filed its Form No. 501-G along with a statement that it intended to take no other action on October 11, 2018. On March 8, 2019, FERC terminated EGT's 501-G proceeding and required no other action. On November 8, 2018, SESH filed its Form No. 501-G and a limited Section 4 rate reduction filing. On December 20, 2018, FERC accepted the limited Section 4 rate reduction effective January 1, 2019 and provided an NGA section 5 investigation moratorium through January 1, 2022. 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 FERC's Form No. 501-G. In MRT's rate case, FERC Docket No. RP18-923, MRT initially filed to recover an income tax allowance to the extent the Partnership's units were owned by entities which were subject to federal income taxation. FERC rejected this approach in a July 31, 2018 Order, and required MRT to re-file its rate case without inclusion of an income tax allowance. MRT re-filed its rate case, exclusive of any allowance for income tax or ADIT. The net effect of these two changes had a minimal impact on MRT's overall cost of service.

Even without action as contemplated in the Final Rule, 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 ADIT 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, 2019, approximately 45% 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, 2019, approximately 14% of our aggregate contracted firm transportation capacity on MRT was subscribed under negotiated rate contracts and approximately 86% of our aggregate contracted firm storage capacity on MRT was subscribed under negotiated rate contracts. As an element of settling MRT's pending FERC rate cases, the majority of our aggregate contracted firm transportation capacity and all of our aggregate contracted firm storage capacity agreements were filed with FERC as negotiated rate contracts. These are pending FERC approval in conjunction with FERC's consideration of the rate case settlements. As of December 31, 2019, approximately 39% and 70% of our aggregate contracted firm transportation capacity on EGT and MRT, respectively, was subscribed under discounted rate contracts. We do not expect negotiated rate agreements 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 FERC or our shippers, 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.

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 FERC pursuant to Section 4 of the Natural Gas Act (2018 Rate Case). 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 FERC's Revised Policy Statement, as a pipeline owned by a master limited partnership, 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 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 master limited partnerships being able to recover an income tax allowance. On November 5, 2019, as supplemented on December 13, 2019, MRT filed an uncontested proposed settlement for the 2018 Rate Case. On October 30, 2019, MRT filed a second general rate case with FERC pursuant to Section 4 of the Natural Gas Act (2019 Rate Case). The 2019 Rate Case was necessary because at the time of filing the 2019 Rate Case, the proposed settlement of the 2018 Rate Case was still being contested, requiring that new maximum rates be established for the non-settling parties reflecting the turnback of capacity. On November 5, 2019, MRT filed an uncontested proposed settlement for the 2019 Rate Case. Subsequently, MRT reached agreement with 100% of the parties participating in the MRT rate cases, and these rate case settlements are pending at FERC. FERC may accept or reject the proposed settlements in the 2018 and 2019 Rate Cases as to all of the parties, or may reject one or both of the settlements and set one or both of the rate cases for hearing.

Market Behavior Rules; Posting and Reporting Requirements

On August 8, 2005, Congress enacted the EPAct of 2005. Among other matters, the EPAct of 2005 amends 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 natural gas sales or natural gas 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 $1.29 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 (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 2.2 Tbtu 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.

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 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 FERC determine not to authorize rates equal to or greater than our currently approved Section 311 rates, our results of operations and cash flows 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 service providers 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 FERC. Although FERC has not made formal determinations with respect to all of our facilities that we consider to be natural gas gathering facilities, management believes that our natural gas gathering pipelines meet the traditional tests that FERC has used to determine that a pipeline is a natural gas gathering pipeline and is therefore not subject to FERC's NGA jurisdiction. The distinction between FERC-regulated transmission services and federally unregulated natural gas gathering services, however, has been the subject of substantial litigation, and FERC determines whether facilities are natural gas gathering facilities on a case-by-case basis, so the classification and regulation of our natural gas gathering 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 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 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 FERC.

States may regulate gathering pipelines. State regulation of natural gas gathering facilities generally includes various safety, environmental and, in some circumstances, requirements prohibiting undue discrimination, and in some instances complaint-based rate regulation. Our natural gas 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 natural gas 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, such as the new rules being promulgated by PHMSA. 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. 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; and
- the throughput underlying the rate.

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 placement 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 results of operations and cash flows 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 $213,268 per day per violation, with a maximum of $2,132,679 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 October 2019, PHMSA published three final rules on pipeline safety. The Enhanced Emergency Order Procedures rule (effective December 2, 2019) implements an existing statutory authorization for PHMSA to issue emergency orders related to pipeline safety if unsafe conditions or practices, or a combination thereof, constitutes or causes an imminent hazard. The Safety of Hazardous Liquid Pipelines rule (effective July 1, 2020) expands PHMSA's regulation of the safety of hazardous liquid pipelines by extending reporting requirements to certain hazardous liquid gravity flow and rural gathering pipelines, establishing new requirements for integrity management programs for hazardous liquid pipelines in high consequence areas (HCAs) and certain other hazardous liquid pipelines, and expanding various inspection and leak detection requirements. For example, the new PHMSA rules require operators of onshore pipeline segments that can accommodate in-line inspection (ILI) tools that are not currently subject to integrity management requirements to complete assessments using ILI tools at least once every ten years. The new rules also require that all hazardous liquids pipelines located in HCAs or areas that could affect HCAs be capable of accommodating ILI tools within 20 years unless certain limited exceptions apply. The Safety of Gas Transmission Pipelines rule (effective July 1, 2020) requires operators of certain gas transmission pipelines to reconfirm the Maximum Allowable Operating Pressure (MAOP) of their lines and establishes a new "Moderate Consequence Area" (MCA) for determining regulatory requirements for gas transmission pipeline segments outside of HCAs. An MCA for gas pipelines is also based on population totals in addition to the existence of certain principal, high-capacity roadways, but an MCA does not meet the relative higher population totals required to be deemed an HCA and therefore such areas are located outside of HCA coverages. The rule also establishes new requirements for conducting baseline assessments and incorporates industry standards and guidelines as well as new requirements for integrity management on pipeline mileage located outside of HCAs (including all MCAs and those Class 3 and Class 4 areas found not to be in HCAs) within 14 years of the publication date of the rule and at least once every 10 years thereafter. We are in the process of assessing the impact of these rules on our future costs of operations and revenue from operations.

PHMSA is working on two additional rules related to gas pipeline safety. The rule entitled “Pipeline Safety: Safety of Gas Transmission Pipelines, Repair Criteria, Integrity Management Improvements, Cathodic Protection, Management of Change, and Other Related Amendments” is expected to adjust the repair criteria for pipelines in HCAs, create new criteria for pipelines in non-HCAs, and strengthen integrity management assessment requirements. The rule entitled “Safety of Gas Gathering Pipelines” is expected to require all gas gathering pipeline operators to report incidents and annual pipeline data and to extend regulatory safety requirements to certain gas gathering pipelines in rural areas. These additional rulemakings are expected to be published and effective by mid-2020. We will begin the process of assessing the impact of these rules when they are published.

Separately, on February 12, 2020, PHMSA published a final rule (effective March 13, 2020) regarding the safety of underground natural gas storage facilities. This rule maintains several elements from the earlier interim rule, incorporating American Petroleum Institute Recommended Practices 1170 and 1171 in PHMSA regulations; revises the definition of underground natural gas storage facility; and clarifies certain reporting and notification criteria. Although the rule may result in increased compliance costs, the changes are not expected to have a material impact on our future costs of operations and revenue from operations.

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 2019, we incurred maintenance capital expenditures and operation and maintenance expenses of $79 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 $84 million in 2020 under our pipeline safety program. This estimate does not include the impact of: the Safety of Hazardous Liquid Pipelines rule and the Safety of Gas Transmission Pipelines rule, both of which will become effective July 1, 2020; or the Pipeline Safety: Safety of Gas Transmission Pipelines, Repair Criteria, Integrity Management Improvements, Cathodic Protection, Management of Change, and Other Related Amendments Rule and the Safety of Gas Gathering Pipelines, both of which are expected to be published and effective by mid-2020. While we cannot predict the outcome of pending or future 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 the new pipeline safety regulations, the pending pipeline safety regulations, and any new pipeline safety laws and regulations associated with our pipeline facilities, which could have a material impact on our costs of operations and revenue from operations.

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. Under the RMP regulations, we have implemented a program to prevent or minimize the consequences of accidental chemical releases at our facilities that use, manufacture and store particular hazardous chemicals. The RMP regulations were amended by the EPA under a final rule published December 19, 2019. The amendments were intended to better address potential security risks and ensure regulatory consistency, and we do not anticipate that they will significantly increase our cost of compliance.

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 crude oil and natural 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, however no action has been taken to date. 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 operations. Compliance with these laws and regulations increases our capital expenditures and operating expenses, and any failure to comply with these laws 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 2019, 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 $2 million in 2020 in maintenance capital expenditures for routine environmental compliance with existing laws and regulations. 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

The threat of climate change continues to attract considerable attention in the United States and in foreign countries. Numerous proposals have been made and could continue to be made at the international, national, regional and state levels of government to monitor and limit existing emissions of GHGs as well as to restrict or eliminate such future emissions. As a result, our operations as well as the operations of our crude oil and natural gas exploration and production customers are subject to a series of regulatory, political, litigation, and financial risks associated with the production and processing of fossil fuels and emission of GHGs.

In the United States, no comprehensive climate change legislation has been implemented at the federal level. However, following the U.S. Supreme Court finding that GHG emissions constitute a pollutant under the CAA, the EPA has adopted regulations that, among other things, establish construction and operating permit reviews for GHG emissions from certain large stationary sources, require the monitoring and annual reporting of GHG emissions from certain petroleum and natural gas system sources in the United States, implement New Source Performance Standards directing the reduction of methane from certain new, modified, or reconstructed facilities in the oil and natural gas sector, and together with the DOT, implement GHG emissions limits on vehicles manufactured for operation in the United States. Additionally, various states and groups of states have adopted or are considering adopting legislation, regulations or other regulatory initiatives that are focused on such areas as GHG cap and trade programs, carbon taxes, reporting and tracking programs, and restriction of emissions. At the international level, there is a non-binding agreement, the United Nations-sponsored “Paris Agreement,” for nations to limit their GHG emissions through individually-determined reduction goals every five years after 2020, although the United States has announced its withdrawal from such agreement, effective November 4, 2020.

Governmental, scientific, and public concern over the threat of climate change arising from GHG emissions has resulted in increasing political risks in the United States, including climate change related pledges made by certain candidates seeking the office of the President of the United States in 2020. Two critical declarations made by one or more candidates running for the Democratic nomination for President include threats to take actions banning hydraulic fracturing of crude oil and natural gas wells and banning new leases for production of minerals on federal properties, including onshore lands and offshore waters. Other actions that could be pursued by presidential candidates may include the imposition of more restrictive requirements for the establishment of pipeline infrastructure or the permitting of LNG export facilities, as well as the reversal of the United States’ withdrawal from the Paris Agreement in November 2020. Litigation risks are also increasing, as a number of cities and other local governments have sought to bring suit against the largest crude oil and natural gas exploration and production companies in state or federal court, alleging, among other things, that such companies created public nuisances by producing fuels that contributed to global warming effects, such as rising sea levels, and therefore are responsible for roadway and infrastructure damages as a result, or alleging that the companies have been aware of the adverse effects of climate change for some time but defrauded their investors by failing to adequately disclose those impacts.

There are also increasing financial risks for fossil fuel producers as shareholders currently invested in fossil-fuel energy companies concerned about the potential effects of climate change may elect in the future to shift some or all of their investments into non-energy related sectors. Institutional lenders who provide financing to fossil-fuel energy companies also have become more attentive to sustainable lending practices and some of them may elect not to provide funding for fossil fuel energy companies. Additionally, the lending practices of institutional lenders have been the subject of intensive lobbying efforts in recent years, oftentimes public in nature, by environmental activists, proponents of the international Paris Agreement, and foreign citizenry concerned about climate change not to provide funding for fossil fuel producers. Limitation of investments in and financings for fossil-fuel energy companies could result in the restriction, delay or cancellation of drilling programs or development or production activities.

The adoption and implementation of new or more stringent international, federal or state legislation, regulations or other regulatory initiatives that impose more stringent standards for GHG emissions from the crude oil and natural gas sector or otherwise restrict the areas in which this sector may produce oil and natural gas or generate GHG emissions could result in increased costs of compliance or costs of consuming, and thereby reduce demand for, oil and natural gas, which could reduce demand for our services and products. Additionally, political, litigation and financial risks may result in our crude oil and natural gas customers restricting or canceling production activities, incurring liability for infrastructure damages as a result of climatic changes, or impairing their ability to continue to operate in an economic manner, which also could reduce demand for our services and products. One or more of these developments could have a material adverse effect on our business, financial condition and results of operations.

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. On January 10, 2020, the Council on Environmental Quality issued a notice of proposed rulemaking to amend the regulations for implementing the procedural provisions of the NEPA. If finalized, the proposed rule would modernize and clarify these regulations, which have not been comprehensively revised since their promulgation in 1978. However, we cannot predict the final form or impacts of these revisions.

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 our areas of operations are designated as critical or suitable habitat for threatened and endangered species. If additional portions of our areas of operations 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. Compliance with all applicable laws providing special protection for designated species has not posed a material cost on our business and operations to date.

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 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.

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 Waters of the United States (WOTUS). Following the change in U.S. presidential administrations, there have been several attempts to modify or eliminate this rule. For example, on January 23, 2020, the EPA and the Corps finalized the Navigable Waters Protection Rule, which narrows the definition of "waters of the United States" relative to the 2015 WOTUS rule. However, legal challenges to the new rule are expected, and multiple challenges to the EPA's prior rulemakings remain pending. Therefore, the scope of jurisdiction under the CWA is uncertain at this time, and any increase in scope could result in increased costs or delays with respect to obtaining permits for such activities as dredge and fill operations in wetland areas. 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 (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 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, 2019, we employ approximately 1,735 employees with an additional 80 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.

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 generally seek to 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, 2019, 57% of our natural gas gathered volumes were attributable to the affiliates of Continental, Vine, GeoSouthern, XTO and Tapstone and 48% of our transportation and storage service revenues were attributable to affiliates of CenterPoint Energy, Spire, OGE Energy, AEP and Continental. 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.

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 public and private 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, 2020, we estimate that expansion capital could range from approximately $160 million to $240 million and our maintenance capital could range from approximately $110 million to $130 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 2019, 4%, 26%, and 70% 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. The Partnership uses certain derivative instruments to manage its commodity price risk exposures.

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.

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 FERC to provide transportation and storage services at our facilities at negotiated rates. As of December 31, 2019, approximately 37% of our aggregate contracted firm transportation capacity on EGT and MRT and 93% of our aggregate contracted firm storage capacity on EGT and MRT, was subscribed under such "negotiated rate" contracts. The majority of our aggregate contracted firm transportation capacity and all of our aggregate contracted firm storage capacity under negotiated rate contracts on MRT are subject to FERC rate case approval. 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 and produced water from our crude oil and produced water 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 Energy, Inc., 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, 2019, CenterPoint Energy owns 53.7% 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. We recorded an impairment to goodwill of $86 million during the year ended December 31, 2019. As of December 31, 2019, we have goodwill of $12 million associated with the Ark-La-Tex Basin reporting unit, which is included in the gathering and processing reportable segment as a result of the acquisition of ETGP 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.

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, 2019, we have 80 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 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.

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, 2019, we had approximately $4.0 billion of long-term debt outstanding, excluding the premiums, discounts and unamortized debt expense on senior notes. In addition, as of December 31, 2019, we had $155 million outstanding under our commercial paper program and $250 million outstanding under our EOIT Senior Notes excluding unamortized premium. We have a $1.75 billion Revolving Credit Facility for working capital, capital expenditures and other partnership purposes, including acquisitions, with no borrowings outstanding, of which approximately $1.59 billion in borrowing capacity was available as of December 31, 2019. As of January 31, 2020, we had $119 million outstanding under our commercial paper program and $1.63

billion of available borrowing capacity under the Revolving Credit Facility. 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.

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 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. Most recently, in August 2019, the EPA proposed amendments to the 2016 standards that, among other things, would remove sources in the transmission and storage segment from the oil and natural gas source category and rescind the methane-specific requirements applicable to sources in the production and processing segments of the industry. As an alternative, the EPA also proposed to rescind the methane-specific requirements that apply to all sources in the oil and natural gas industry, without removing the transmission and storage sources from the current source category. Legal challenges to any final rulemaking that rescinds the 2016 standards are expected. As a result of the foregoing, 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 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. The EPA has also 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. Some state regulatory agencies have adopted 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 or other regulatory mechanisms.

Our and our customers' operations are subject to a series of risks arising out of the threat of climate change that could result in increased operating costs, adversely impact our results of operations and ability to make cash distributions to unitholders, limit the areas in which oil and natural gas production may occur, and reduce demand for the products and services we provide.

The threat of climate change continues to attract considerable attention in the United States and in foreign countries. Numerous proposals have been made and could continue to be made at the international, national, regional and state levels of government to monitor and limit existing emissions of GHGs as well as to restrict or eliminate such future emissions. As a result, our operations as well as the operations of our oil and natural gas exploration and production customers are subject to a series of regulatory, political, litigation, and financial risks associated with the production and processing of fossil fuels and emission of GHGs.

In the United States, no comprehensive climate change legislation has been implemented at the federal level. However, following the U.S. Supreme Court finding that GHG emissions constitute a pollutant under the CAA, the EPA has adopted regulations that, among other things, establish construction and operating permit reviews for GHG emissions from certain large stationary sources, require the monitoring and annual reporting of GHG emissions from certain petroleum and natural gas system sources in the United States, implement New Source Performance Standards directing the reduction of methane from certain new, modified, or reconstructed facilities in the oil and natural gas sector, and together with the DOT, implement GHG emissions limits on vehicles manufactured for operation in the United States. Additionally, various states and groups of states have adopted or are considering adopting legislation, regulations or other regulatory initiatives that are focused on such areas as GHG cap and trade programs, carbon taxes, reporting and tracking programs, and restriction of emissions. At the international level, there is a non-binding agreement, the United Nations-sponsored "Paris Agreement," for nations to limit their GHG emissions through individually-determined reduction goals every five years after 2020, although the United States has announced its withdrawal from such agreement, effective November 4, 2020.

Governmental, scientific, and public concern over the threat of climate change arising from GHG emissions has resulted in increasing political risks in the United States, including climate change related pledges made by certain candidates seeking the office of the President of the United States in 2020. Two critical declarations made by one or more candidates running for the Democratic nomination for President include threats to take actions banning hydraulic fracturing of oil and natural gas wells and banning new leases for production of minerals on federal properties, including onshore lands and offshore waters. Other actions that could be pursued by presidential candidates may include the imposition of more restrictive requirements for the establishment of pipeline infrastructure or the permitting of LNG export facilities, as well as the reversal of the United States' withdrawal from the Paris Agreement in November 2020. Litigation risks are also increasing, as a number of cities and other local governments have sought to bring suit against the largest oil and natural gas exploration and production companies in state or federal court, alleging, among other things, that such companies created public nuisances by producing fuels that contributed to global warming effects, such as rising sea levels, and therefore are responsible for roadway and infrastructure damages as a result, or alleging that the companies have been aware of the adverse effects of climate change for some time but defrauded their investors by failing to adequately disclose those impacts.

There are also increasing financial risks for fossil fuel producers as shareholders currently invested in fossil-fuel energy companies concerned about the potential effects of climate change may elect in the future to shift some or all of their investments into non-energy related sectors. Institutional lenders who provide financing to fossil-fuel energy companies also have become more attentive to sustainable lending practices and some of them may elect not to provide funding for fossil fuel energy companies. Additionally, the lending practices of institutional lenders have been the subject of intensive lobbying efforts in recent years, oftentimes public in nature, by environmental activists, proponents of the international Paris Agreement, and foreign citizenry concerned about climate change not to provide funding for fossil fuel producers. Limitation of investments in and financings for fossil fuel energy companies could result in the restriction, delay or cancellation of drilling programs or development or production activities.

The adoption and implementation of new or more stringent international, federal or state legislation, regulations or other regulatory initiatives that impose more stringent standards for GHG emissions from the oil and natural gas sector or otherwise restrict the areas in which this sector may produce oil and natural gas or generate GHG emissions could result in increased costs of compliance or costs of consuming, and thereby reduce demand for, oil and natural gas, which could reduce demand for our services and products. Additionally, political, litigation and financial risks may result in our oil and natural gas customers restricting or canceling production activities, incurring liability for infrastructure damages as a result of climatic changes, or impairing their ability to continue to operate in an economic manner, which also could reduce demand for our services and products. One or more of these developments could have a material adverse effect on our business, financial condition, results of operations and ability to make cash distributions to unitholders.

Finally, many 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 and ability to make cash distributions to unitholders.

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 $1.29 million per day for each violation and possible criminal penalties of up to approximately $1.29 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, 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.

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 $79 million in 2019 and currently estimate that we will incur maintenance capital expenditures and operation and maintenance expenses of up to $84 million in 2020 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 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 existing pipeline safety regulations may result in increased operating and compliance costs. For example, in October 2019, PHMSA published three final rules on pipeline safety. The Enhanced Emergency Order Procedures rule (effective December 2, 2019) implements an existing statutory authorization for PHMSA to issue emergency orders related to pipeline safety if unsafe conditions or practices, or a combination thereof, constitutes or causes an imminent hazard. The Safety of Hazardous Liquid Pipelines rule (effective July 1, 2020) expands PHMSA's regulation of the safety of hazardous liquid pipelines by extending reporting requirements to certain hazardous liquid gravity flow and rural gathering pipelines, establishing new requirements for integrity management programs for hazardous liquid pipelines in HCAs and certain other hazardous liquid pipelines, and expanding various inspection and leak detection requirements. For example, the new PHMSA rules require operators of onshore pipeline segments that can accommodate ILI tools that are not currently subject to integrity management requirements to complete assessments using ILI tools at least once every ten years. The new rules also require that all hazardous liquids pipelines located in HCAs or areas that could affect HCAs be capable of accommodating ILI tools within 20 years unless certain limited exceptions apply. The Safety of Gas Transmission Pipelines rule (effective July 1, 2020) requires operators of certain gas transmission pipelines to reconfirm the MAOP of their lines and establishes a new MCA for determining regulatory requirements for gas transmission pipeline segments outside of HCAs. An MCA for gas pipelines is also based on population totals in addition to the existence of certain principal, high-capacity roadways, but an MCA does not meet the relative higher population totals required to be deemed an HCA and therefore such areas are located outside of HCA coverages. The rule also establishes new requirements for conducting baseline assessments and incorporates industry standards and guidelines as well as new requirements for integrity management on pipeline mileage located outside of HCAs (including all MCAs and those Class 3 and Class 4 areas found not to be in HCAs) within 14 years of the publication date of the rule and at least once every 10 years thereafter. We are in the process of assessing the impact of these rules on our future costs of operations and revenue from operations.

PHMSA is working on two additional rules related to gas pipeline safety. The rule entitled "Pipeline Safety: Safety of Gas Transmission Pipelines, Repair Criteria, Integrity Management Improvements, Cathodic Protection, Management of Change, and Other Related Amendments" is expected to adjust the repair criteria for pipelines in HCAs, create new criteria for pipelines in non-HCAs, and strengthen integrity management assessment requirements. The rule entitled "Safety of Gas Gathering Pipelines" is expected to require all gas gathering pipeline operators to report incidents and annual pipeline data and to extend regulatory safety requirements to certain gas gathering pipelines in rural areas. These additional rulemakings are expected to be effective by mid-2020. The adoption of these or other 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 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 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 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 January 31, 2020, affiliates of our general partner owned 79.2% 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 unitholder approval, which would dilute existing unitholder 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 January 31, 2020, 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. The sale of these units in the public or private markets could have an adverse impact on the price of the common units or on any trading market that may develop. In addition, 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 January 31, 2020, affiliates of our general partner owned approximately 79.2% 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 January 31, 2020, affiliates of our general partner will then own 80.9% 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. 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.

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 is currently 21% 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 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 would affect publicly traded partnerships. For example, the “Clean Energy for America Act,” which is similar to legislation that was commonly proposed during the Obama administration, was introduced in the Senate on May 2, 2019. If enacted, this proposal would, among other things, repeal 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 U.S. federal income tax purposes.

There can be no assurance that there will not be further changes to U.S. federal income tax laws or the U.S. Department of the Treasury’s interpretation of the qualifying income rules in a manner that could impact our ability to qualify as a partnership in the future. 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 on 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. For the purposes of this limitation, our adjusted taxable income is computed without regard to any business interest expense or business interest income, and in the case of taxable years beginning before January 1, 2022, any deduction allowable for depreciation, amortization, or depletion to the extent such depreciation, amortization, or depletion is not capitalized into cost of goods sold with respect to inventory. 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 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 tax 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 generally 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). The U.S. Department of the Treasury has provided interim guidance permitting aggregation of certain similarly situated businesses or activities pending publication of proposed regulations. 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.

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.

Moreover, the transferee of an interest in a partnership that is engaged in a U.S. trade or business is generally 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. Because the "amount realized" includes a partner's share of the partnership's liabilities, 10.0% of the amount realized could exceed the total cash purchase price for our common units. However, pending the issuance of final regulations, the IRS has suspended the application of this withholding requirement to the disposition of a publicly traded interest in a publicly traded partnership (such as us). U.S. Department of the Treasury and the IRS have recently proposed regulations that would provide, with respect to transfers of publicly traded interests in publicly traded partnerships effected through a broker, that the obligation to withhold is imposed on the transferor's broker and that a partner's "amount realized" does not include a partner's share of a publicly traded partnership's liabilities for purposes of determining the amount subject to withholding. It is not clear when such regulations will be finalized and if they will be finalized in their current form. 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 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 154,584 square feet of leased office space at 499 West Sheridan Avenue, Suite 1500, 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.

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.

We are required to describe administrative proceedings arising under laws regulating the discharge of materials into the environment or for the purpose of protecting the environment that involve potential monetary sanctions of $100,000 or more. On January 27, 2020, we received a Notice of Probable Violation ("NOPV") from PHMSA, advising us of alleged violations of pipeline safety regulations by EGT and recommending that EGT be preliminarily assessed civil penalties of $147,100 with respect to three of the alleged violations as follows: $51,100, $31,400, and $64,600, respectively. We are evaluating the allegations, but we cannot guarantee that the ultimate resolution of this matter will result in civil penalties of less than $100,000.

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 January 31, 2020, there were 435,206,963 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.

Distributions to Common Units

Our minimum quarterly distribution to our common units as set forth in the Partnership Agreement is $0.2875 per common unit per quarter. Our current quarterly distribution is $0.3305 per common unit per quarter. There is no guarantee that we will continue to pay the current quarterly distribution or the minimum quarterly distribution to our common units in any quarter. For more information on cash distributions, see Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operation — Liquidity and Capital Resources" contained herein.

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,				
	2019	2018	2017	2016	2015
	(In millions, except for per unit data)				
Results of Operations Data:					
Revenues [1]	$ 2,960	$ 3,431	$ 2,803	$ 2,272	$ 2,418
Cost of natural gas and natural gas liquids, excluding depreciation and amortization [1]	1,279	1,819	1,381	1,017	1,097
Operation and maintenance, General and administrative	526	501	464	465	522
Depreciation and amortization	433	398	366	338	318
Impairments	86	—	—	9	1,134
Taxes other than income tax	67	65	64	58	59
Operating income (loss)	569	648	528	385	(712)
Interest expense	(190)	(152)	(120)	(99)	(90)
Equity in earnings of equity method affiliates	17	26	28	28	29
Other, net	3	—	—	—	2
Income (loss) before income taxes	399	522	436	314	(771)
Income tax (benefit) expense	(1)	(1)	(1)	1	—
Net income (loss)	$ 400	$ 523	$ 437	$ 313	$ (771)
Less: Net income (loss) attributable to noncontrolling interests	4	2	1	1	(19)
Net income (loss) attributable to limited partners	$ 396	$ 521	$ 436	$ 312	$ (752)
Less: Series A Preferred Unit distributions	36	36	36	22	—
Net income (loss) attributable to common and subordinated units	$ 360	$ 485	$ 400	$ 290	$ (752)
Basic earnings (loss) per common limited partner unit	$ 0.83	$ 1.12	$ 0.92	$ 0.69	$ (1.78)
Diluted earnings (loss) per common limited partner unit	$ 0.82	$ 1.11	$ 0.92	$ 0.69	$ (1.78)
Basic and diluted earnings (loss) per subordinated limited partner unit [2]	$ —	$ —	$ 0.93	$ 0.68	$ (1.78)
Distributions declared per unit [3]	$ 1.3095	$ 1.2720	$ 1.2720	$ 1.2720	$ 1.2645

(1) Revenues and Cost of natural gas and natural gas liquids, excluding depreciation and amortization are shown under the guidance of ASC 606 for 2019 and 2018 and under ASC 605 for 2017 and prior.

(2) Basic and diluted earnings per subordinated unit reflect net income (loss) attributable to the Partnership. 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.

(3) Distributions are in accordance with the Partnership Agreement. Distributions declared per unit relate to common and subordinated units.

	December 31,				
	2019	2018	2017	2016	2015
	(In millions)				
Balance Sheet Data (at period end):					
Property, plant and equipment, net	$ 10,870	$ 10,871	$ 10,355	$ 10,143	$ 10,131
Total assets	12,266	12,444	11,593	11,212	11,226
Total debt	4,375	4,278	3,450	2,993	3,270
Partners' Equity	7,409	7,618	7,654	7,794	7,531

	Year Ended December 31,				
	2019	2018	2017	2016	2015
	(In millions, except for operating data)				
Cash Flow Data:					
Net cash flows provided by (used in):					
Operating activities	$ 942	$ 924	$ 834	$ 721	$ 726
Investing activities	(430)	(1,154)	(706)	(367)	(946)
Financing activities	(530)	233	(132)	(335)	212
Other Financial Data (1)**:**					
Gross margin	$ 1,681	$ 1,612	$ 1,422	$ 1,255	$ 1,321
Adjusted EBITDA	1,147	1,074	924	873	801
DCF	784	760	660	639	538
Operating Data:					
Natural gas gathered volumes—TBtu	1,666	1,637	1,300	1,143	1,148
Natural gas gathered volumes—TBtu/d	4.56	4.48	3.56	3.13	3.14
Natural gas processed volumes—TBtu (2)	925	877	715	658	651
Natural gas processed volumes—TBtu/d (2)	2.53	2.40	1.96	1.80	1.78
NGLs produced—MBbl/d (2)(3)	128.58	129.98	90.11	78.70	73.55
NGLs sold—MBbl/d (3)(4)	131.59	132.06	92.21	78.16	75.55
Condensate sold—MBbl/d	7.41	5.90	4.79	5.27	5.13
Crude oil and condensate gathered volumes—MBbl/d	128.46	41.07	25.56	25.00	13.86
Transported volumes—TBtu	2,254	2,028	1,838	1,788	1,814
Transported volumes—TBtu/d	6.18	5.56	5.04	4.88	4.97
Interstate firm contracted capacity—Bcf/d	6.31	5.94	6.21	7.04	7.19
Intrastate average deliveries—TBtu/d	2.14	2.08	1.88	1.72	1.84

(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) Includes volumes provided under third-party processing arrangements.

(3) Excludes condensate.

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

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.

Discussions of 2017 items and year-to-year comparisons between 2018 and 2017 that are not included in this Annual Report on Form 10-K can be found in Part II, Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations" of our Annual Report on Form 10-K for the fiscal year ended December 31, 2018.

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." 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 13,500 miles of natural gas gathering pipelines, 15 natural gas processing plants with approximately 2.6 Bcf/d of processing capacity and approximately 1,187,900 horsepower of compression as of December 31, 2019 in the Anadarko, Arkoma and Ark-La-Tex Basins. In addition, our gathering and processing assets include approximately 175 miles of crude oil and condensate gathering pipelines (including EOCS) 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.

Financing

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.

On January 29, 2019, the Partnership entered into a $1 billion three-year unsecured term loan agreement. The term loan can be prepaid at any time, in whole or in part, without penalty and includes two, one-year extension options, subject to lender approval. The term loan also contains substantially the same covenants as those contained in the Partnership's Revolving Credit Facility. On September 16, 2019, the Partnership prepaid $200 million of the advances under the Term Loan Agreement, the repayment of which was not subject to LIBOR breakage costs. As of December 31, 2019, there was $800 million outstanding under the 2019 Term Loan Agreement.

On September 13, 2019, the Partnership completed the public offering of $550 million aggregate principal amount of its 4.150% Senior Notes due 2029 (2029 Notes). The Partnership received net proceeds of approximately $544 million, after deducting the underwriting discount and offering expenses. The net proceeds were used to repay $200 million of borrowings outstanding under the 2019 Term Loan Agreement, to repay amounts outstanding under the commercial paper program until the EOIT Senior Notes maturity in March 2020, and for general partnership purposes. The Partnership intends to issue commercial paper to repay the full amount of the EOIT Senior Notes at maturity in March 2020.

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 can be 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 affected by drilling and production. Our gathering and processing segment primarily serves producers, and many producers utilize the services provided by our transportation and storage segment. A decrease in volumes on our systems due to a decrease in drilling or production by our producer customers could adversely affect the results of operations 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.”

Commodity Supply and Demand Dynamics

In the United States, the focus of natural gas and crude oil production has moved towards unconventional resource plays. Advancements in technology have allowed producers to efficiently extract natural gas and crude oil from these plays. As a result, the proven reserves and production of natural gas and crude oil in the United States have increased to historically high levels. As production levels have continued to increase, natural gas and crude oil supply has outpaced growth in domestic demand, resulting in declines in the market prices for natural gas, NGLs and crude oil in the near term and in greater needs for exports to balance the market.

Natural gas continues to be a critical component of energy demand in the United States. Although supply is expected to continue to outpace demand in the near term, management believes that the prospects for continued natural gas demand are favorable over the long-term and will be driven by price and availability of natural gas, in combination with population and economic growth, continuing decreases in nuclear and coal-fired power generation due to retirements, and the continuing development of the global export market for LNG. We believe that continuing consumption of natural gas over the long-term, both within the United States and in the global export market for LNG, will continue to drive demand for our natural gas gathering, processing, transportation and storage services.

In addition to domestic supply and demand, crude oil prices in the United State are also significantly influenced by international market dynamics. While domestic production has outpaced demand within the United States, exports of crude oil and refined petroleum products have increased. We believe that sustained consumption of crude oil over the long-term within the United States and continuing growth in exports to global export markets will continue to drive demand for our crude oil gathering services.

Capital Market Volatility

We may access the capital markets to fund our expansion capital expenditures, re-finance maturing debt obligations or for other general partnership purposes. In addition, our customers may also rely on the capital markets for similar purposes. Drivers of energy capital markets volatility can include, but are not limited to, fluctuations in commodity prices as well as other macro-economic factors. During periods of capital market volatility, investor interest in new or outstanding equity or debt securities can decline. Such declines in the energy capital markets may impact our business by limiting our or our customers' ability 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 recent years, energy equity prices have underperformed the broader market as investors have favored other sectors. In addition, unit prices of midstream master limited partnerships have experienced volatility and amounts of equity capital raised in the public markets by these partnerships in total have been reduced in recent years. In response, we have focused on funding more of our expansion capital expenditures with internally generated cash flows. We expect for the capital markets to continue to be volatile in the near term and believe that maintaining financial flexibility will contribute to our ability to execute on our business strategies. 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 recently issued new pipeline safety regulations, which may increase our compliance costs. 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 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. 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, natural gas liquids and condensate 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."

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 for the Years Ended December 31, 2019 and 2018

The following tables summarizes the composition of our results of operations for the years ended December 31, 2019 and 2018.

December 31, 2019	Gathering and Processing	Transportation and Storage	Eliminations	Enable Midstream Partners, LP
		(In millions)		
Product sales	$ 1,449	$ 487	$ (403)	$ 1,533
Service revenues	889	551	(13)	1,427
Total Revenues	2,338	1,038	(416)	2,960
Cost of natural gas and natural gas liquids (excluding depreciation and amortization shown separately)	1,203	491	(415)	1,279
Gross margin [1]	1,135	547	(1)	1,681
Operation and maintenance, General and administrative	320	207	(1)	526
Depreciation and amortization	308	125	—	433
Impairments	86	—	—	86
Taxes other than income tax	41	26	—	67
Operating income	$ 380	$ 189	$ —	$ 569
Equity in earnings of equity method affiliate	$ —	$ 17	$ —	$ 17

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 revenues	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

(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.

	Year Ended December 31,	
	2019	2018
Operating Data:		
Natural gas gathered volumes—TBtu	1,666	1,637
Natural gas gathered volumes—TBtu/d	4.56	4.48
Natural gas processed volumes—TBtu	925	877
Natural gas processed volumes—TBtu/d	2.53	2.40
NGLs produced—MBbl/d [(1)]	128.58	129.98
NGLs sold—MBbl/d [(1)(2)]	131.59	132.06
Condensate sold—MBbl/d	7.41	5.90
Crude oil and condensate gathered volumes—MBbl/d	128.46	41.07
Transported volumes—TBtu	2,254	2,028
Transported volumes—TBtu/d	6.18	5.56
Interstate firm contracted capacity—Bcf/d	6.31	5.94
Intrastate average deliveries—TBtu/d	2.14	2.08

	Year Ended December 31,	
	2019	**2018**
Operating Data By Basin:		
Anadarko		
Natural gas gathered volumes—TBtu/d	2.34	2.21
Natural gas processed volumes—TBtu/d	2.10	1.99
NGLs produced—MBbl/d (1)	113.20	113.63
Crude oil and condensate gathered volumes—MBbl/d	92.70	12.14
Arkoma		
Natural gas gathered volumes—TBtu/d	0.47	0.55
Natural gas processed volumes—TBtu/d	0.09	0.10
NGLs produced—MBbl/d (1)	5.42	6.55
Ark-La-Tex		
Natural gas gathered volumes—TBtu/d	1.75	1.72
Natural gas processed volumes—TBtu/d	0.34	0.31
NGLs produced—MBbl/d (1)	9.96	9.80
Williston		
Crude oil gathered volumes—MBbl/d	35.76	28.93

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

Gathering and Processing

2019 compared to 2018. Our gathering and processing segment reported operating income of $380 million for 2019 compared to $464 million for 2018. The difference of $84 million in operating income between periods was primarily due to the recognition of $86 million in goodwill impairment in 2019, a $45 million increase in depreciation and amortization, an $8 million increase in operation and maintenance and general and administrative expenses and a $3 million increase in taxes other than income tax. This was partially offset by a $58 million increase in gross margin in 2019.

Our gathering and processing segment revenues decreased $480 million in 2019. The decrease was primarily due to the following:

Product Sales:

- revenues from NGL sales decreased $462 million primarily due to a decrease in the average realized sales price from lower average market prices for all NGL products and higher volumes subject to fee deductions for NGLs sold under certain third-party processing arrangements, partially offset by higher processed volumes in the Anadarko and Ark-La-Tex Basins,
- revenues from natural gas sales decreased $112 million due to lower average natural gas sales prices and lower sales volumes, and
- changes in the fair value of natural gas, condensate and NGL derivatives decreased $37 million.

These decreases were partially offset by:

- realized gains on natural gas, condensate and NGL derivatives increased $44 million.

Service Revenues:

- processing service revenues decreased $19 million due to lower consideration received from percent-of-proceeds, percent-of-liquids and keep-whole processing arrangements due to a decrease in the average realized price, partially offset by higher processed volumes in the Anadarko and Ark-La-Tex Basins.

This decrease was offset by:

- natural gas gathering revenues increased $65 million due to higher fees and gathered volumes in the Anadarko and Ark-La-Tex Basins and higher revenue associated with the amendment of certain minimum volume commitment contracts in the Arkoma Basin, partially offset by lower gathered volumes in the Arkoma Basin and lower shortfall payments associated with the expiration of certain minimum volume commitment contracts in the Arkoma Basin,
- crude oil, condensate and produced water gathering revenues increased $40 million primarily due to an increase related to the November 2018 acquisition of EOCS and an increase in volumes in the Williston Basin, partially offset by lower average gathering rates in the Williston Basin, and

- a $1 million increase in intercompany management fees.

Our gathering and processing segment gross margin increased $58 million in 2019. The increase was primarily due to the following:

- natural gas gathering fees increased $65 million due to higher fees and gathered volumes in the Anadarko and Ark-La-Tex Basins and higher revenue associated with the amendment of certain minimum volume commitment contracts in the Arkoma Basin, partially offset by lower gathered volumes in the Arkoma Basin and lower shortfall payments associated with the expiration of certain minimum volume commitment contracts in the Arkoma Basin,
- realized gains on natural gas, condensate and NGL derivatives increased $44 million,
- crude oil, condensate and produced water gathering revenues increased $40 million primarily due to an increase related to the November 2018 acquisition of EOCS and an increase in volumes in the Williston Basin, partially offset by lower average gathering rates in the Williston Basin, and
- a $1 million increase in intercompany management fees.

These increases were partially offset by:

- changes in the fair value of natural gas, condensate and NGL derivatives decreased $37 million,
- revenues from NGL sales less the cost of NGLs decreased $22 million due to lower average sales prices for all NGL products, partially offset by higher processed volumes in the Anadarko and Ark-La-Tex Basins,
- processing service fees decreased $19 million due to lower consideration received from percent-of-proceeds, percent-of-liquids and keep-whole processing arrangements due to a decrease in the average realized price, partially offset by higher processed volumes in the Anadarko and Ark-La-Tex Basins, and
- revenues from natural gas sales less the cost of natural gas decreased approximately $14 million due to lower average natural gas sales prices and lower sales volumes.

Our gathering and processing segment operation and maintenance and general and administrative expenses increased $8 million in 2019. The increase was primarily due to a $10 million increase in payroll-related costs, a $4 million loss on retirement of assets during 2019 with no comparable item in 2018, a $3 million increase in utilities and insurance as a result of additional assets in service, and a $1 million increase due to lower capitalized overhead costs. These increases were partially offset by a $3 million decrease in materials and supplies due to the timing of operation and maintenance activities and a $7 million decrease in contract services expenses primarily due to expenses related to the EOCS acquisition in 2018.

Our gathering and processing segment depreciation and amortization expense increased $45 million in 2019 primarily due to an increase of $20 million in depreciation from the implementation of new rates from the 2019 depreciation study, $14 million increase of amortization of customer intangibles acquired as part of the acquisition of EOCS in the fourth quarter of 2018 and an $11 million increase in depreciation related to other additional assets placed in service.

During 2019, our gathering and processing segment recognized an impairment of $86 million of goodwill associated with the Anadarko Basin reporting unit. Due to the continuing decreases in forward commodity prices, the reduction in forecasted producer activities, the resulting decrease in our forecasted cash flows and the increase in the weighted average cost of capital, the Partnership determined that the fair value of the goodwill associated with our Anadarko Basin reporting unit was completely impaired and recognized $86 million of impairment.

Our gathering and processing segment taxes other than income tax increased $3 million in 2019 due to higher accrued ad valorem taxes due to additional assets placed in service.

Transportation and Storage

2019 compared to 2018. Our transportation and storage segment reported operating income of $189 million for 2019 as compared to $183 million for 2018. The difference of $6 million in operating income between periods was primarily due to a $13 million increase in gross margin, a $10 million decrease in depreciation and amortization and a $1 million decrease in taxes other than income taxes. This was partially offset by an $18 million increase in operation and maintenance and general and administrative expenses in 2019.

Our transportation and storage segment revenues decreased $124 million in 2019. The decrease was primarily due to the following:

Product Sales:

- revenues from natural gas sales decreased $126 million primarily due to lower sales volumes and lower average sales price,
- revenues from NGL sales decreased $11 million due to lower average sales prices and lower volumes, and
- realized gains on natural gas derivatives decreased $1 million.

Service Revenues:

- volume-dependent transportation revenues decreased $3 million due to a decrease in off-system intrastate transportation offset by new off-system interstate transportation contracts.

This decrease was partially offset by:

- firm transportation and storage services increased $17 million due to new intrastate and interstate transportation contracts partially offset by lower revenue due to the reduction of contracted interstate storage capacity.

Our transportation and storage segment gross margin increased $13 million in 2019. The increase was primarily due the following:

- firm transportation and storage services increased $17 million due to new intrastate and interstate transportation contracts partially offset by lower revenue due to the reduction of contracted interstate storage capacity, and
- system management activities increased $11 million.

These increases were partially offset by:

- revenues from NGL sales less the cost of NGLs decreased $7 million due to a decrease in average NGL prices and lower volumes,
- natural gas storage inventory decreased $4 million due to additional lower of cost or net realizable value adjustments,
- volume-dependent transportation revenues decreased $3 million due to a decrease in off-system intrastate transportation offset by new off-system interstate transportation contracts, and
- realized gains on natural gas derivatives decreased $1 million.

Our transportation and storage segment operation and maintenance and general and administrative expenses increased $18 million in 2019. The increase was primarily due to a $12 million increase in materials and supplies and outside services due to pipeline safety and storage integrity work under our pipeline safety program and to comply with certain PHMSA regulations, a $4 million loss on retirement of assets during 2019 with no comparable item in 2018, a $2 million increase in reserves for claims settlement costs, a $2 million increase in payroll-related costs and a $1 million increase in intercompany management fees. These increases were partially offset by a $4 million decrease in information-technology related costs.

Our transportation and storage segment depreciation and amortization expense decreased $10 million in 2019 primarily due to a decrease of $10 million in depreciation from the implementation of new intrastate natural gas pipeline depreciation rates from the 2019 depreciation study.

Our transportation and storage segment taxes other than income tax decreased $1 million due to favorable tax settlements.

Consolidated Information

	Year Ended December 31,	
	2019	2018
	(In millions)	
Operating Income	$ 569	$ 648
Other Income (Expense):		
Interest expense	(190)	(152)
Equity in earnings of equity method affiliate	17	26
Other, net	3	—
Total Other Expense	(170)	(126)
Income Before Income Taxes	399	522
Income tax benefit	(1)	(1)
Net Income	$ 400	$ 523
Less: Net income attributable to noncontrolling interests	4	2
Net Income attributable to limited partners	$ 396	$ 521
Less: Series A Preferred Unit distributions	36	36
Net Income attributable to common units	$ 360	$ 485

2019 compared to 2018

Net Income attributable to limited partners. We reported net income attributable to limited partners of $396 million in 2019 compared to $521 million in 2018. The decrease in net income attributable to limited partners was primarily due to a decrease in operating income of $79 million, an increase in interest expense of $38 million and a decrease in equity in earnings of equity method affiliate of $9 million.

Interest Expense. Interest expense increased by $38 million in 2019 due to an increase in principal amounts and interest rates on the Partnership's outstanding debt.

Equity in Earnings of Equity Method Affiliate. Equity in earnings of equity method affiliate decreased $9 million primarily due to an increase in ad valorem taxes of approximately $5 million due to the expiration of a property tax credit, a decrease of $2 million in revenues due to expiring contracts partially offset by interruptible volumes and an increase of $2 million in operating expenses.

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 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, 2019	Year Ended December 31, 2018
	(In millions)	
Reconciliation of Gross Margin to Total Revenues:		
Consolidated		
Product sales	$ 1,533	$ 2,106
Service revenues	1,427	1,325
Total Revenues	2,960	3,431
Cost of natural gas and natural gas liquids (excluding depreciation and amortization)	1,279	1,819
Gross margin	$ 1,681	$ 1,612
Reportable Segments		
Gathering and Processing		
Product sales	$ 1,449	$ 2,016
Service revenues	889	802
Total Revenues	2,338	2,818
Cost of natural gas and natural gas liquids (excluding depreciation and amortization)	1,203	1,741
Gross margin	$ 1,135	$ 1,077
Transportation and Storage		
Product sales	$ 487	$ 625
Service revenues	551	537
Total Revenues	1,038	1,162
Cost of natural gas and natural gas liquids (excluding depreciation and amortization)	491	628
Gross margin	$ 547	$ 534

The following tables show the components of our gross margin for the year ended December 31, 2019 and 2018.

	Fee-Based			
	Demand/ Commitment/ Guaranteed Return	Volume Dependent	Commodity-Based	Total
Year Ended December 31, 2019				
Gathering and Processing Segment	24%	56%	20 %	100%
Transportation and Storage Segment	89%	12%	(1)%	100%
Partnership Weighted Average	45%	41%	14 %	100%

	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%

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Reconciliation of Adjusted EBITDA and DCF to net income attributable to limited partners and calculation of Distribution coverage ratio:	Year Ended December 31, 2019	Year Ended December 31, 2018
	(In millions, except Distribution coverage ratio)	
Net income attributable to limited partners	$ 396	$ 521
Depreciation and amortization expense	433	398
Interest expense, net of interest income	188	152
Income tax benefit	(1)	(1)
Distributions received from equity method affiliate in excess of equity earnings	8	7
Non-cash equity-based compensation	16	16
Change in fair value of derivatives [1]	11	(26)
Other non-cash losses [2]	12	7
Impairments	86	—
Noncontrolling Interest Share of Adjusted EBITDA	(2)	—
Adjusted EBITDA	$ 1,147	$ 1,074
Series A Preferred Unit distributions [3]	(36)	(36)
Distributions for phantom and performance units [4]	(10)	(5)
Adjusted interest expense [5]	(191)	(159)
Maintenance capital expenditures	(126)	(114)
Current income taxes	—	—
DCF	$ 784	$ 760
Distributions related to common unitholders [6]	$ 570	$ 552
Distribution coverage ratio	1.38	1.38

(1) Change in fair value of derivatives includes changes in the fair value of derivatives that are not designated as hedging instruments.
(2) Other non-cash losses primarily include net loss on sale of assets.
(3) This amount represents the quarterly cash distributions on the Series A Preferred Units declared for the years ended December 31, 2019, 2018 and 2017. 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.
(4) 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.
(5) See below for a reconciliation of Adjusted interest expense to Interest expense.
(6) Represents cash distributions declared for common units outstanding as of each respective period. Amounts for 2019 reflect estimated cash distributions for common units outstanding for the quarter ended December 31, 2019.

	Year Ended December 31, 2019	Year Ended December 31, 2018
	(In millions)	
Reconciliation of Adjusted EBITDA to net cash provided by operating activities:		
Net cash provided by operating activities	$ 942	$ 924
Interest expense, net of interest income	188	152
Net income attributable to noncontrolling interests	(4)	(2)
Other non-cash items	2	7
Proceeds from insurance	1	2
Changes in operating working capital which (provided) used cash:		
Accounts receivable	(37)	11
Accounts payable	78	(6)
Other, including changes in noncurrent assets and liabilities	(42)	5
Return of investment in equity method affiliate	8	7
Change in fair value of derivatives	11	(26)
Adjusted EBITDA	$ 1,147	$ 1,074

	Year Ended December 31, 2019	Year Ended December 31, 2018
	(In millions)	
Reconciliation of Adjusted interest expense to Interest expense:		
Interest Expense	$ 190	$ 152
Interest Income	(2)	—
Amortization of premium on long-term debt	6	6
Capitalized interest on expansion capital	2	6
Amortization of debt expense and discount	(5)	(5)
Adjusted interest expense	$ 191	$ 159

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 debt maturities, 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, 2019, we had a working capital deficit of $391 million. The deficit is primarily due to the classification of $251 million of the EOIT Senior Notes as Current Portion of long-term debt as of December 31, 2019, as well as $155 million of commercial paper outstanding as of December 31, 2019. 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,	
	2019	2018
	(In millions)	
Net cash provided by operating activities	$ 942	$ 924
Net cash used in investing activities	(430)	(1,154)
Net cash (used in) provided by financing activities	(530)	233

Operating Activities

The increase of $18 million, or 2%, in net cash provided by operating activities for the year ended December 31, 2019 as compared to the year ended December 31, 2018 is primarily due to an increase in adjustments for non-cash items of $128 million, an increase of $13 million in the timing of cash receipts and disbursements and changes in other working capital assets and liabilities, partially offset by a decrease in net income of $123 million.

Investing Activities

The decrease of $724 million, or 63%, in net cash used in investing activities for the year ended December 31, 2019 as compared to the year ended December 31, 2018 was primarily due to the $443 million acquisition of EOCS in 2018, net of cash received compared to no acquisitions in 2019, lower capital expenditures of $296 million and an increase in the return of investment in equity method affiliates of $1 million, partially offset by an increase in other investing outflows of $8 million, decreased proceeds from the sale of assets of $7 million due to the 2018 sale of a cryogenic processing plant compared to a minor asset sale for the year ended December 31, 2019 and a decrease in proceeds from insurance of $1 million.

Financing Activities

Net cash provided by financing activities decreased $763 million, or 327%, for the year ended December 31, 2019 as compared to the year ended December 31, 2018. Our primary financing activities consist of the following:

	Year Ended December 31,	
	2019	2018
	(In millions)	
(Decrease) increase in short-term debt	$ (494)	$ 244
Net proceeds (repayments) of term loans	800	(450)
Net (repayments) proceeds of Revolving Credit Facility	(250)	250
Repayment of 2019 Notes	(500)	—
Proceeds from 2029 Notes, net of issuance costs	544	—
Proceeds from 2028 Notes, net of issuance costs	—	787
Proceeds from issuance of common units, net of issuance costs	—	2
Distributions	(605)	(591)
Cash paid for employee equity-based compensation	(25)	(9)

Sources of Liquidity

As of December 31, 2019, our sources of liquidity included:

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

Please see Note 7 “Partners’ Equity” and Note 12 “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 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, 2019, the Partnership did not sell any common units under the ATM Program. For the year ended December 31, 2018, the Partnership sold an aggregate of 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. As of December 31, 2019, approximately $197 million of common units of aggregate offering price remained available for issuance through the ATM Program.

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, 2020, we estimate that expansion capital could range from approximately $160 million to $240 million and our maintenance capital could range from approximately $110 million to $130 million. Our future expansion capital expenditures may vary significantly from period to period based on commodity prices, producer activities 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 $0.3305 per unit, or $1.322 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 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.

We paid or have authorized payment of the following cash distributions to common unitholders, as applicable, during the years ended December 31, 2019 and 2018 (in millions, except for per unit amounts):

Quarter Ended	Record Date	Payment Date	Per Unit Distribution	Total Cash Distribution
2019				
December 31, 2019 (1)	February 18, 2020	February 25, 2020	$ 0.3305	$ 144
September 30, 2019	November 19, 2019	November 26, 2019	$ 0.3305	$ 144
June 30, 2019	August 20, 2019	August 27, 2019	$ 0.3305	$ 144
March 31, 2019	May 21, 2019	May 29, 2019	$ 0.318	$ 138
2018				
December 31, 2018	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

(1) The Board of Directors declared this $0.3305 per common unit cash distribution on February 7, 2020, to be paid on February 25, 2020, to unitholders of record at the close of business on February 18, 2020.

The Partnership has 14,520,000 Series A Preferred Units outstanding as of December 31, 2019. 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 7 "Partners' Equity" included in Item 8. "Financial Statements and Supplementary Data—Notes to the Consolidated Financial Statements."

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, 2019 and 2018 (in millions, except for per unit amounts):

Quarter Ended	Record Date	Payment Date	Per Unit Distribution	Total Cash Distribution
2019				
December 31, 2019 (1)	February 7, 2020	February 14, 2020	$ 0.625	$ 9
September 30, 2019	November 5, 2019	November 14, 2019	$ 0.625	$ 9
June 30, 2019	August 2, 2019	August 14, 2019	$ 0.625	$ 9
March 31, 2019	April 29, 2019	May 15, 2019	$ 0.625	$ 9
2018				
December 31, 2018	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

(1) The Board of Directors declared a $0.625 per Series A Preferred Unit cash distribution on February 7, 2020, to be paid on February 14, 2020 to Series A Preferred unitholders of record at the close of business on February 7, 2020.

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, 2019 and our best estimate of the period in which the obligation will be settled:

	2020	2021-2022	2023-2024	After 2024	Total
			(In millions)		
Maturities of outstanding debt (1)(2)	$ 405	$ 800	$ 600	$ 2,600	$ 4,405
Noncancellable operating leases	11	13	10	10	44
Purchase obligations (3):					
Minimum volume commitments (4)	66	132	132	90	420
Other purchase obligations (5)	27	6	2	—	35
Total contractual obligations	$ 509	$ 951	$ 744	$ 2,700	$ 4,904

(1) Contractual interest payments associated with long-term debt are $152 million, $288 million, $277 million and $866 million in 2020, 2021 through 2022, 2023 through 2024 and after 2024, respectively.
(2) Excludes premium (discount) on long-term debt of $7 million.
(3) A purchase obligation represents an agreement to purchase goods or services that is enforceable, legally binding and specifies all significant terms, including: fixed minimum or variable prices provisions; and the approximate timing of the transaction. Purchase obligations require estimation and actual amounts may vary depending on prices and volume at the time of delivery.
(4) Includes minimum volume commitment fees related to certain third party gathering, processing and fractionation agreements.
(5) Includes (i) commitments for capital expenditures, operating expenses, service contracts and utilities, (ii) noncancellable commitments to purchase physical quantities of commodities in future periods and (iii) unconditional payment obligations under firm pipeline transportation contracts.

Off-Balance Sheet Arrangements

We do not have any off-balance sheet arrangements.

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. The Partnership recorded no impairments to long-lived assets in the years ended December 31, 2019 or 2018. Based upon review of forecasted undiscounted cash flows as of December 31, 2019, 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. The resulting fair value of the reporting unit is then compared to the carrying amount of the reporting unit and an impairment charge is recorded to goodwill for the difference. The Partnership performs its goodwill impairment testing at the reporting unit, which is 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 commodity price declines, throughput declines, contracted capacity declines, cost increases, increases in cost of capital, regulatory or political environment changes and other changes in market conditions such as decreased prices in market-based transactions for similar assets.

During the fourth quarter of the year ended December 31, 2018, as a result of the acquisition of EOCS, the Partnership recorded $86 million of goodwill within the Anadarko Basin reporting unit. The Partnership performed a quantitative test for our annual goodwill impairment analysis as of October 1, 2019, and determined that the carrying value of the Anadarko Basin reporting unit exceeded its fair value and that goodwill associated with the Anadarko Basin reporting unit was completely impaired in the amount of $86 million. The impairment is included in Impairments on the Consolidated Statements of Income for the year ended December 31, 2019. As of December 31, 2019, the Partnership had $12 million of goodwill associated with the Ark-La-Tex reporting unit within the gathering and processing reportable segment on its Consolidated Balance Sheet.

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 revenues 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 revenues: Service revenues represent 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 of the Notes to Consolidated Financial Statements in Part II, 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 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, 2019 and 2018, respectively.

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 year ended December 31, 2018, the Partnership completed acquisitions accounted for as business combinations as discussed in Note 5 "Acquisitions" in the Notes to Consolidated Financial Statements in Part II, Item 8. "Financial Statements and Supplementary Data." 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.

New Accounting Pronouncements

For a description of new accounting pronouncements, see Note 2 “New Accounting Pronouncements” in the Notes to Consolidated Financial Statements in Part II, Item 8. “Financial Statements and Supplementary Data.”

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 13 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 11% of our gross margin for the twelve months ending December 31, 2020 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, 2019, we have entered into additional derivative contracts to further manage our exposure to commodity price risk for the twelve months ending December 31, 2020.

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 $9 million for natural gas and ethane and $10 million for NGLs (other than ethane) and condensate, excluding the impact of hedges for the twelve months ending December 31, 2020.

Interest Rate Risk

Our current interest rate risk exposure is related primarily to our debt portfolio. Our debt portfolio includes senior notes with a fixed rate of interest, 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, 2019 Term Loan Agreement and any issuances under our commercial paper program are at a variable interest rate and expose us to the risk of increasing interest rates. The Partnership utilizes derivatives to mitigate the risk of interest changes. We do not enter into risk management contracts for speculative purposes. For further information regarding our derivatives, see Note 13 of the Notes to Consolidated Financial Statements in Part II, Item 8. “Financial Statements and Supplementary Data.”

Based upon the $955 million outstanding borrowings under our commercial paper program and 2019 Term Loan Agreement as of December 31, 2019, excluding the impact of hedges and holding all other variables constant, a 100 basis-point, or 1%, increase in interest rates would increase our annual interest expense by approximately $10 million. For further information regarding our interest rates, see Note 12 of the Notes to Consolidated Financial Statements in Part II, Item 8. “Financial Statements and Supplementary Data.”

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, 2019 and 2018, the related consolidated statements of income, comprehensive income, cash flows, and partners’ equity for each of the three years in the period ended December 31, 2019, 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, 2019 and 2018, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2019, 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, 2019, 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, 2020, 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.

Critical Audit Matter

The critical audit matter communicated below is a matter arising from the current-period audit of the financial statements that was communicated or required to be communicated to the audit committee and that (1) relates to accounts or disclosures that are material to the financial statements and (2) involved our especially challenging, subjective, or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the financial statements, taken as a whole, and we are not, by communicating the critical audit matter below, providing a separate opinion on the critical audit matter or on the accounts or disclosures to which it relates.

Goodwill - Anadarko Basin Reporting Unit - Refer to Notes 1 and 10 to the consolidated financial statements

Critical Audit Matter Description

The Partnership's evaluation of goodwill for impairment involves the comparison of the fair value of each reporting unit to its carrying value. The Partnership used the discounted cash flow model to estimate fair value, which requires management to make significant estimates and assumptions related to the weighted average cost of capital and forecasts of future revenues, including the revenue growth rate. Changes in these assumptions could have a significant impact on either the fair value, the amount of any goodwill impairment charge, or both. The goodwill balance allocated to the Anadarko Basin Reporting Unit ("Anadarko") was $86 million as of October 1, 2019. The carrying value of Anadarko exceeded its fair value as of the measurement date and the goodwill associated with Anadarko was completely impaired in the amount of $86 million.

Given the significant judgments made by management to estimate the fair value of Anadarko, performing audit procedures to evaluate the reasonableness of management's estimates and assumptions related to selection of the weighted average cost of capital and forecasts of future revenues, including the revenue growth rate, of Anadarko required a high degree of auditor judgment and an increased extent of effort, including the need to involve our fair value specialists.

How the Critical Audit Matter Was Addressed in the Audit

Our audit procedures related to the weighted average cost of capital and forecasts of future revenues, including the revenue growth rate, used by management to estimate the fair value of Anadarko included the following, among others:

- We tested the effectiveness of controls over management's goodwill impairment evaluation, including those over the determination of the fair value of Anadarko, such as controls related to management's selection of the weighted average cost of capital and forecasts of future revenues, including the revenue growth rate.

- We evaluated management's ability to accurately forecast future revenues by comparing actual results to management's historical forecasts.

- We evaluated the reasonableness of management's revenue forecasts by comparing the forecasts to:

  – Historical revenues.
  – Internal communications to management and the Board of Directors.
  – Forecasted information included in Partnership press releases as well as in analyst and industry reports for the Partnership and certain of its peer companies.

- With the assistance of our fair value specialists, we evaluated the reasonableness of the (1) valuation methodology and (2) weighted average cost of capital and revenue growth rate by:

  – Testing the source information underlying the determination of the weighted average cost of capital and revenue growth rate and the mathematical accuracy of the calculation.
  – Developing a range of independent estimates and comparing those to the weighted average cost of capital and revenue growth rate selected by management.

/s/ DELOITTE & TOUCHE

Oklahoma City, Oklahoma
February 19, 2020

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

ENABLE MIDSTREAM PARTNERS, LP
CONSOLIDATED STATEMENTS OF INCOME

	Year Ended December 31,		
	2019	**2018**	**2017**
	(In millions, except per unit data)		
Revenues (including revenues from affiliates (Note 16)):			
Product sales	$ 1,533	$ 2,106	$ 1,653
Service revenues	1,427	1,325	1,150
Total Revenues	2,960	3,431	2,803
Cost and Expenses (including expenses from affiliates (Note 16)):			
Cost of natural gas and natural gas liquids (excluding depreciation and amortization shown separately)	1,279	1,819	1,381
Operation and maintenance	423	388	369
General and administrative	103	113	95
Depreciation and amortization	433	398	366
Impairment (Note 10)	86	—	—
Taxes other than income taxes	67	65	64
Total Cost and Expenses	2,391	2,783	2,275
Operating Income	569	648	528
Other Income (Expense):			
Interest expense	(190)	(152)	(120)
Equity in earnings of equity method affiliate	17	26	28
Other, net	3	—	—
Total Other Expense	(170)	(126)	(92)
Income Before Income Tax	399	522	436
Income tax benefit	(1)	(1)	(1)
Net Income	$ 400	$ 523	$ 437
Less: Net income attributable to noncontrolling interests	4	2	1
Net Income Attributable to Limited Partners	$ 396	$ 521	$ 436
Less: Series A Preferred Unit distributions (Note 7)	36	36	36
Net Income Attributable to Common and Subordinated Units (Note 6)	$ 360	$ 485	$ 400
Basic earnings per unit (Note 6)			
Common units	$ 0.83	$ 1.12	$ 0.92
Subordinated units	$ —	$ —	$ 0.93
Diluted earnings per unit (Note 6)			
Common units	$ 0.82	$ 1.11	$ 0.92
Subordinated units	$ —	$ —	$ 0.93

See Notes to the Consolidated Financial Statements

ENABLE MIDSTREAM PARTNERS, LP
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	Year Ended December 31,		
	2019	2018	2017
	(In millions)		
Net income	$ 400	$ 523	$ 437
Other comprehensive loss:			
Unrealized losses on derivative instruments	(3)	—	—
Reclassification of derivative losses to net income	—	—	—
Other comprehensive loss	(3)	—	—
Comprehensive income	397	523	437
Less: Comprehensive income attributable to noncontrolling interests	4	2	1
Comprehensive income attributable to Limited Partners	$ 393	$ 521	$ 436

See Notes to the Consolidated Financial Statements

ENABLE MIDSTREAM PARTNERS, LP
CONSOLIDATED BALANCE SHEETS

	December 31, 2019	December 31, 2018
	(In millions, except units)	
Current Assets:		
Cash and cash equivalents	$ 4	$ 8
Restricted cash	—	14
Accounts receivable, net of allowance for doubtful accounts (Note 1)	244	290
Accounts receivable—affiliated companies	25	19
Inventory	46	50
Gas imbalances	35	29
Other current assets	35	39
Total current assets	389	449
Property, Plant and Equipment:		
Property, plant and equipment	13,161	12,899
Less accumulated depreciation and amortization	2,291	2,028
Property, plant and equipment, net	10,870	10,871
Other Assets:		
Intangible assets, net	601	663
Goodwill	12	98
Investment in equity method affiliate	309	317
Other	85	46
Total other assets	1,007	1,124
Total Assets	$ 12,266	$ 12,444
Current Liabilities:		
Accounts payable	$ 161	$ 288
Accounts payable—affiliated companies	1	4
Short-term debt	155	649
Current portion of long-term debt	251	500
Taxes accrued	32	31
Gas imbalances	19	22
Accrued compensation	31	26
Customer deposits	17	38
Other	113	57
Total current liabilities	780	1,615
Other Liabilities:		
Accumulated deferred income taxes, net	4	5
Regulatory liabilities	24	23
Other	80	54
Total other liabilities	108	82
Long-Term Debt	3,969	3,129
Commitments and Contingencies (Note 17)		
Partners' Equity:		
Series A Preferred Units (14,520,000 issued and outstanding at December 31, 2019 and December 31, 2018, respectively)	362	362
Common units (435,201,365 issued and outstanding at December 31, 2019 and 433,232,411 issued and outstanding at December 31, 2018, respectively)	7,013	7,218
Accumulated other comprehensive loss	(3)	—
Noncontrolling interests	37	38
Total Partners' Equity	7,409	7,618
Total Liabilities and Partners' Equity	$ 12,266	$ 12,444

See Notes to the Consolidated Financial Statements

ENABLE MIDSTREAM PARTNERS, LP
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	2019	2018	2017
	(In millions)		
Cash Flows from Operating Activities:			
Net income	$ 400	$ 523	$ 437
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	433	398	366
Deferred income taxes	(1)	(1)	(3)
Impairment	86	—	—
Loss on sale/retirement of assets	8	1	7
Equity in earnings of equity method affiliate	(17)	(26)	(28)
Return on investment in equity method affiliate	17	26	28
Equity-based compensation	16	16	15
Amortization of debt costs and discount (premium)	(1)	(1)	(2)
Changes in other assets and liabilities:			
Accounts receivable, net	43	(10)	(23)
Accounts receivable—affiliated companies	(6)	(1)	(5)
Inventory	4	(10)	1
Gas imbalance assets	(6)	8	4
Other current assets	9	(21)	4
Other assets	11	(12)	1
Accounts payable	(75)	4	54
Accounts payable—affiliated companies	(3)	1	—
Gas imbalance liabilities	(3)	10	(23)
Other current liabilities	39	4	(4)
Other liabilities	(12)	15	5
Net cash provided by operating activities	942	924	834
Cash Flows from Investing Activities:			
Capital expenditures	(432)	(728)	(416)
Acquisitions, net of cash acquired	—	(443)	(298)
Proceeds from sale of assets	1	8	1
Proceeds from insurance	1	2	2
Return of investment in equity method affiliate	8	7	5
Other, net	(8)	—	—
Net cash used in investing activities	(430)	(1,154)	(706)
Cash Flows from Financing Activities:			
(Decrease) increase in short-term debt	(494)	244	405
Proceeds from long-term debt, net of issuance costs	1,544	787	691
Repayment of long-term debt	(700)	(450)	—
Proceeds from Revolving Credit Facility	—	350	1,200
Repayment of Revolving Credit Facility	(250)	(100)	(1,836)
Proceeds from issuance of common units, net of issuance costs	—	2	—
Distributions to common unitholders	(564)	(551)	(355)
Distributions to subordinated unitholders	—	—	(198)
Distributions to preferred unitholders	(36)	(36)	(36)
Distributions to non-controlling interests	(5)	(4)	(1)
Cash paid for employee equity-based compensation	(25)	(9)	(2)
Net cash (used in) provided by financing activities	(530)	233	(132)
Net (Decrease) Increase in Cash, Cash Equivalents and Restricted Cash	(18)	3	(4)
Cash, Cash Equivalents and Restricted Cash at Beginning of Period	22	19	23
Cash, Cash Equivalents and Restricted Cash at End of Period	$ 4	$ 22	$ 19

See Notes to the Consolidated Financial Statements

ENABLE MIDSTREAM PARTNERS, LP
CONSOLIDATED STATEMENTS OF PARTNERS' EQUITY

	Series A Preferred Units		Common Units		Subordinated Units		Accumulated Other Comprehensive Earnings	Noncontrolling Interest	Total Partners' Equity
	Units	Value	Units	Value	Units	Value	Value	Value	Value
					(In millions)				
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
Net income	—	36	—	360	—	—	—	4	400
Other comprehensive loss	—	—	—	—	—	—	(3)	—	(3)
Distributions	—	(36)	—	(564)	—	—	—	(5)	(605)
Equity-based compensation, net of units for employee taxes	—	—	2	(1)	—	—	—	—	(1)
Balance as of December 31, 2019	15	$ 362	435	$ 7,013	—	$ —	$ (3)	$ 37	$ 7,409

See Notes to the Consolidated Financial Statements

ENABLE MIDSTREAM PARTNERS, LP
NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

(1) Summary of Significant Accounting Policies

Organization

Enable Midstream Partners, LP (Partnership) is a Delaware limited partnership formed on May 1, 2013. 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, 2019, CenterPoint Energy held approximately 53.7% or 233,856,623 of the Partnership's common units, and OGE Energy held approximately 25.5% or 110,982,805 of the Partnership's common units. Additionally, CenterPoint Energy holds 14,520,000 Series A Preferred Units. See Note 7 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, 2019, 2018 and 2017, the Partnership owned a 50% interest in SESH. See Note 11 for further discussion of SESH. For the years ended December 31, 2019, 2018 and 2017, 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, 2019, the Partnership owned a 60% interest in ESCP, which is consolidated in its Consolidated Financial Statements as EOCS acted as the managing member of ESCP and had control over the operations of ESCP.

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 20.

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 revenues 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 revenues: Service revenues represent 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 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 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. For the year ended December 31, 2019, one non-affiliate customer accounted for approximately 11%, or $328 million of our consolidated revenue. These revenues were primarily included in our gathering and processing segment. There are no revenue concentrations with individual non-affiliate customers in the years ended December 31, 2018 and 2017. See note 16 for more information on revenues from affiliates.

Additionally, for the years ended December 31, 2019, 2018 and 2017, one third party purchased approximately 12%, 12% and 13%, respectively, of the NGLs delivered off our system, which accounted for approximately $131 million, $214 million and $140 million, or 4%, 6% and 5%, respectively, of total revenues. Additionally, in the years ended December 31, 2019, 2018 and 2017, another third party purchased 12%, 8% and 12%, respectively, of the NGLs delivered off our system, which accounted for $119 million, $152 million and $127 million, respectively, or 4%, 4% and 4%, respectively, of total revenues.

Natural Gas and Natural Gas Liquids Purchases

Cost of natural gas and natural gas liquids represents the cost of our natural gas and natural gas liquids purchased exclusive of depreciation, Operation and maintenance and General and administrative expenses and consists primarily of product and fuel costs. Estimates for gas purchases are based on estimated volumes and contracted purchase prices. Estimated gas purchases are included in Accounts Payable or Accounts Payable-affiliated companies, as appropriate, on the Consolidated Balance Sheets and in Cost of natural gas and natural gas liquids, excluding Depreciation and amortization on the Consolidated Statements of Income.

Operation and Maintenance and General and Administrative Expense

Operation and maintenance expense represents the cost of our service related revenues and consists primarily of labor expenses, lease costs, utility costs, insurance premiums and repairs and maintenance expenses directly related to 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, 2019 or 2018.

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 18.

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 $4 million and $8 million of cash and cash equivalents as of December 31, 2019 and 2018, respectively.

Restricted Cash

Restricted cash consists of cash which is restricted by agreements with third parties. The Consolidated Balance Sheets have $0 and $14 million of restricted cash as of December 31, 2019 and 2018, respectively.

Accounts Receivable and Allowance for Doubtful Accounts

Accounts receivable are recorded at the invoiced amount and do not typically bear interest. The determination of the allowance for doubtful accounts requires management to make estimates and judgments regarding our customers' ability to pay. The allowance for doubtful accounts is determined based upon specific identification and estimates of future uncollectable amounts. On an ongoing basis, we evaluate our customers' financial strength based on aging of accounts receivable, payment history and review of other relevant information, including ratings agency credit ratings and alerts, publicly available reports and news releases, and bank and trade references. It is the policy of management to review the outstanding accounts receivable at least quarterly, giving consideration to historical bad debt write-offs, the aging of receivables and specific customer circumstances that may impact their ability to pay the amounts due. Based on this review, management determined that a $2 million allowance for doubtful accounts was required at each of the years ended December 31, 2019 and 2018.

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 each of the years ended December 31, 2019 and 2018, and $1 million for the year ended December 31, 2017. 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 reportable 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 reportable 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, 2019, 2018 and 2017, the Partnership recorded write-downs to net realizable value related to natural gas and natural gas liquids inventory of $8 million, $4 million and $2 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,	
	2019	2018
	(In millions)	
Materials and supplies	$ 32	$ 31
Natural gas and natural gas liquids	14	19
Total Inventory	$ 46	$ 50

Gas Imbalances

Gas imbalances occur when the actual amounts of natural gas delivered from or received by the Partnership's pipeline systems differ from the amounts scheduled to be delivered or received. Imbalances are due to or due from shippers and operators and can be settled in cash or natural gas depending on contractual terms. The Partnership values all imbalances at individual, or where appropriate an average of, current market indices applicable to the Partnership's operations, not to exceed net realizable value.

Long-Lived Assets (including Intangible Assets)

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

Assessing Impairment of Long-lived Assets (including Intangible Assets) and Goodwill

The Partnership periodically evaluates long-lived assets, including property, plant and equipment, and specifically identifiable intangibles other than goodwill, when events or changes in circumstances indicate that the carrying value of these assets may not be recoverable. The determination of whether an impairment has occurred is based on an estimate of undiscounted cash flows attributable to the assets, as compared to the carrying value of the assets. For more information, see Note 14.

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. The resulting fair value of the reporting unit is then compared to the carrying amount of the reporting unit and an impairment charge is recorded to goodwill for the difference. The Partnership performs its goodwill impairment testing at the reporting unit, which is one level below the transportation and storage and gathering and processing reportable segment level. For more information, see Note 10.

Regulatory Assets and Liabilities

The Partnership applies the guidance for accounting for regulated operations to portions of the transportation and storage reportable 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, 2019 and 2018, these removal costs of $24 million and $23 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, 2019, 2018 and 2017, the Partnership capitalized interest and AFUDC of $2 million, $6 million and $1 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 commodity 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 commodity 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 commodity 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.

At times, the Partnership utilizes interest rate derivative instruments such as swaps to mitigate the impact of changes in interest rates on its operating results and cash flows. Such derivatives are recognized in the Partnership's Consolidated Balance Sheets at their fair value. For interest rate derivative instruments designated as cash flow hedging instruments, the gain or loss on the derivative is recognized in Accumulated other comprehensive loss and will be reclassified to Interest expense in the same period in which the hedged transaction is recognized in earnings.

The Partnership's policies prohibit the use of leveraged financial instruments. A leveraged financial instrument, for this purpose, is a transaction involving a derivative whose financial impact will be based on an amount other than the notional amount or volume of the instrument.

Fair Value Measurements

The Partnership determines fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. As required, the Partnership utilizes valuation techniques that maximize the use of observable inputs (levels 1 and 2) and minimize the use of unobservable inputs (level 3) within the fair value hierarchy included in current accounting guidance. The Partnership generally applies the market approach to determine fair value. This method uses pricing and other information generated by market transactions for identical or comparable assets and liabilities. Assets and liabilities are classified within the fair value hierarchy based on the lowest level (least observable) input that is significant to the measurement in its entirety.

Equity-Based Compensation

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

Employee Benefit Plans

On January 1, 2015, the Partnership adopted the 401(k) Savings Plan, covering all full-time employees. Participant contributions are discretionary, and can be up to 70% of compensation, as pre-tax, Roth, and /or after-tax contributions, subject to certain limits. We match 100% of employee contributions up to 6% of each participant's eligible annual compensation, subject to certain limits. Matching contributions provided by the Partnership are immediately vested. The Partnership may also make discretionary profit sharing contributions. Allocations of such profit sharing contributions are based on the proportion of each participant's eligible compensation of the plan year to the total of all participants' eligible compensation, as defined. A participant must be employed on the last day of the Plan year in order to receive an allocation of profit sharing contributions. Profit sharing contributions must be approved by the Board of Directors annually. For the years ended December 31, 2019, 2018 and 2017, the Partnership contributed $20 million, $19 million and $18 million, respectively.

During the years ended December 31, 2019, 2018 and 2017, 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, 2019, 2018 and 2017, the Partnership reimbursed OGE Energy $3 million, $3 million and $5 million, respectively, for these benefits. See Note 16 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

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 manner. 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 expects to adopt this standard in the first quarter of 2020 and 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, although early adoption is permitted for interim or annual goodwill impairment tests performed on testing dates after January 1, 2017. The Partnership elected to adopt the guidance in ASU 2017-04 effective October 1, 2019, and as a result applied the new guidance to its annual goodwill impairment test performed as of October 1, 2019. The impairment resulting from the October 1, 2019 annual impairment test was based upon the amount by which the carrying amount exceeded the reporting unit's fair value up to the actual amount of goodwill recorded for the Anadarko Basin reporting unit.

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

In August 2018, the FASB issued ASU No. 2018-13, "Fair Value Measurement (Topic 820): Disclosure Framework—Changes to the Disclosure Requirements for Fair Value Measurement" which focuses on improving the effectiveness of disclosures in the notes to the financial statements by facilitating clear communication of the information required by U.S. 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 this standard in the first quarter of 2020 and 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—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 expects to adopt this standard in the first quarter of 2020 and does not expect the adoption of this standard to have a 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 expects to adopt this standard in the first quarter of 2020 and does not expect the adoption of this standard to have a material impact on our Consolidated Financial Statements and related disclosures.

Codification Improvements

In April 2019, the FASB issued ASU No. 2019-04, “Codification Improvements to Topic 326, Financial Instruments-Credit Losses, Topic 815, Derivatives and Hedging, and Topic 825, Financial Instruments,” which clarifies and improves areas of guidance related to recently issued standards on credit losses, hedging and recognition and measurement. The standard is effective for interim and annual periods beginning after December 15, 2019. The Partnership expects to adopt this standard in the first quarter of 2020 and does not expect the adoption of this standard to have a material impact on our Consolidated Financial Statements and related disclosures.

In November 2019, FASB issued ASU No. 2019-11, “Codification Improvements to Topic 326, Financial Instruments-Credit Losses,” which introduced an expected credit loss model for the impairment of financial assets measured at amortized cost basis to replace the probable, incurred loss model for those assets. The standard is effective for interim and annual periods beginning after December 15, 2019. The Partnership expects to adopt this standard in the first quarter of 2020 and 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 only to contracts that were not expired as of January 1, 2018.

The following tables disaggregate total revenues by major source from contracts with customers and the gain on derivative activity for the years ended December 31, 2019 and 2018.

	Year Ended December 31, 2019			
	Gathering and Processing	Transportation and Storage	Eliminations	Total
	(In millions)			
Revenues:				
Product sales:				
Natural gas	$ 368	$ 464	$ (384)	$ 448
Natural gas liquids	943	19	(19)	943
Condensate	126	—	—	126
Total revenues from natural gas, natural gas liquids, and condensate	1,437	483	(403)	1,517
Gain on derivative activity	12	4	—	16
Total Product sales	$ 1,449	$ 487	$ (403)	$ 1,533
Service revenues:				
Demand revenues	$ 274	$ 489	$ —	$ 763
Volume-dependent revenues	615	62	(13)	664
Total Service revenues	$ 889	$ 551	$ (13)	$ 1,427
Total Revenues	$ 2,338	$ 1,038	$ (416)	$ 2,960

	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 at the point in time 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 13 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 typically contain a series of distinct services performed on discrete volumes. For these types of contracts with customers, we typically have a right to consideration from our customers in an amount that corresponds directly with the value to the customer of our performance completed to date and recognize service revenues in accordance with our election to use the right to invoice practical expedient.

Demand revenues

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

- Under a firm arrangement, a customer agrees to pay a fixed fee for a contractually agreed upon pipeline or storage capacity, which results in performance obligations for each individual period of reservation. Once the services have been completed, or the customer no longer has access to the contracted capacity, revenue is recognized.
- Under a minimum volume commitment arrangement, a customer agrees to pay the contractually agreed upon gathering, compressing and treating fees for a minimum volume of natural gas or crude oil irrespective of whether or not the minimum volume of natural gas or crude oil is delivered, which results in performance obligations for each individual unit of volume. If the actual volumes exceed the minimum volume of natural gas or crude oil, the customer pays the contractually agreed upon gathering, compressing and treating fees for the excess volumes in addition to the fees paid for the minimum volume of natural gas or crude oil. 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 revenues are generally variable because the volumes are dependent on throughput by third-party customers for which the service provided is only specified on a daily or monthly basis. Our other fee revenue arrangements typically recognize revenue as the service is performed and 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.

The following table summarizes the components of accounts receivable:

	December 31, 2019	December 31, 2018
	(In millions)	
Accounts Receivable:		
Customers	$ 239	$ 297
Contract assets [1]	18	6
Non-customers	12	6
Total Accounts Receivable [2]	$ 269	$ 309

(1) Contract assets reflected in Total Accounts Receivable include accrued minimum volume commitments. Contract assets are primarily attributable to revenues associated with estimated shortfall volumes on certain annual minimum volume commitment arrangements. Total Accounts Receivable does not include $6 million of contract assets related to firm transportation contracts with tiered rates, which are reflected in Other Assets.

(2) Total Accounts Receivable includes Accounts receivables, net of allowance for doubtful accounts and Accounts receivable—affiliated companies.

Contract Liabilities

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

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

The table below summarizes the change in the contract liabilities for the year ended December 31, 2019:

	December 31, 2019	December 31, 2018	Amounts recognized in revenues
		(In millions)	
Deferred revenues [1]	$ 48	$ 48	$ 24

The table below summarizes the timing of recognition of these contract liabilities as of December 31, 2019:

	2020	2021	2022	2023	2024 and After
			(In millions)		
Deferred revenues [1]	$ 25	$ 6	$ 6	$ 5	$ 6

(1) Deferred revenues includes deferred revenue—affiliated companies. This amount is included in Other current liabilities and Other long-term liabilities.

Remaining Performance Obligations

We apply certain practical expedients as permitted by ASC 606, in which we are not required to disclose information regarding remaining performance obligations associated with agreements with original expected durations of one year or less, agreements in which we have elected to recognize revenue in the amount to which we have the right to invoice, and agreements where the variable consideration is allocated entirely to wholly unsatisfied performance obligations that generally do not get resolved until actual volumes are delivered and the prices are known. However, certain agreements do not qualify for practical expedients, which consist primarily of firm arrangements and minimum volume commitment arrangements. Upon completion of the performance obligations associated with these arrangements, 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, 2019:

	2020	2021	2022	2023	2024 and After
			(In millions)		
Transportation and Storage [1]	$ 461	$ 298	$ 238	$ 225	$ 699
Gathering and Processing	137	121	123	121	313
Total remaining performance obligations	$ 598	$ 419	$ 361	$ 346	$ 1,012

(1) The remaining performance obligations include certain obligations for MRT, which are calculated based on rates that are subject to FERC rate case approval.

(4) Leases

On January 1, 2019, the Partnership adopted 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. The Partnership has applied the standard only to contracts that were not expired as of January 1, 2019.

The Partnership elected the 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 elected the optional transition practical expedient to not reassess whether any expired or existing contracts are or contain leases, the lease classification for any expired or existing leases and initial direct costs for any existing leases. Upon adoption, we increased 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 were classified as operating leases. The

Partnership did not recognize a material cumulative adjustment to the Consolidated Statement of Partners' Equity and we did not have any material changes in the timing of expense recognition or our accounting policies.

Our lease obligations are primarily comprised of rentals of field equipment and buildings, which are recorded as Operation and maintenance and General and administrative expenses in the Partnership's Consolidated Statements of Income. Other than the contractual terms for each lease obligation, the key inputs for our calculations of the initial right-of-use assets and corresponding lease liabilities are the expected remaining life and applicable discount rate. Field equipment has an expected lease term of three to five years, with contractual base terms of one to three years followed by month-to-month renewals. Field equipment rental arrangements do not generally contain any significant variable lease payments. While certain arrangements may include lower standby rates, field equipment is generally anticipated to be in use for all of its expected lease term. Buildings have an expected lease term of seven to ten years, which is currently the same as the contractual base term. Building rental arrangements contain market-based renewal options of up to 15 years. Variable lease payments for buildings are generally comprised of costs for utilities, maintenance and building management services. Variable lease payments due under building rental arrangements began July 1, 2019, with amounts due monthly. The Partnership is generally not aware of the implicit rate for either field equipment or building rental arrangements, so discount rates are based upon the expected term of each arrangement and the Partnership's uncollateralized borrowing rate associated with the expected term at the time of lease inception. As of December 31, 2019, the weighted average remaining lease term is 6.4 years and the weighted average discount rate is 5.40%.

As of December 31, 2019, we have right-of-use assets of $37 million recorded as Other Assets, $9 million of corresponding obligations recorded as Other Current Liabilities and $31 million of corresponding obligations recorded as Other Liabilities on the Partnership's Consolidated Balance Sheet. All lease obligations outstanding during the year ended December 31, 2019 were classified as operating leases. Therefore, all cash flows are reflected in Cash Flows from Operating Activities. Total lease costs comprised of field equipment rentals and buildings rentals were $29 million and $7 million in the Consolidated Statements of Income during the year ended December 31, 2019, respectively.

The table below summarizes lease cost for the year ended December 31, 2019:

	Year Ended December 31, 2019		
	Gathering and Processing	Transportation and Storage	Total
	(In millions)		
Lease Cost:			
Operating lease cost	$ 11	$ —	$ 11
Short-term lease cost	22	2	24
Variable lease cost	1	—	1
Total Lease Cost	$ 34	$ 2	$ 36

Under ASC 842, as of December 31, 2019, the Partnership has operating lease obligations expiring at various dates. The $4 million difference between undiscounted cash flows for operating leases and our $40 million of lease obligations is due to the impact of the applicable discount rate. Undiscounted cash flows for operating lease liabilities are as follows:

	Year Ended December 31,						
	2020	2021	2022	2023	2024	2025 and After	Total
	(In millions)						
Noncancellable operating leases	$ 11	$ 7	$ 6	$ 6	$ 4	$ 10	$ 44

Description of Lease Contracts

The Partnership occupied 162,053 square feet of office space at its former principle executive offices under a lease that expired June 30, 2019. The lease payments were $19 million over the lease term, which began April 1, 2012. These lease costs are included in General and administrative expense in the Consolidated Statements of Income.

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

On August 28, 2018, the Partnership entered into a lease to occupy 154,584 feet of office space for its principle executive offices in Oklahoma City, Oklahoma, which expires June 30, 2029. The lease payments commenced on July 1, 2019, and total $25 million over the lease term, as well as a proportionate percentage of facility expenses. The Partnership relocated its headquarters to the new location during the second quarter of 2019. Minimum lease payments were $1 million in 2019 and are expected to be $2 million per year from 2020 through 2023.

The Partnership currently has 86 compression service agreements, of which 71 agreements are on a month-to-month basis and 15 agreements will expire in 2020. The Partnership also has nine gas treating lease agreements, of which seven are on a month-to-month basis, one agreement will expire in 2021 and one agreement will expire in 2022. These lease costs are reflected in Operation and maintenance expense in the Consolidated Statements of Income.

ASC 840 Lease Accounting

Under ASC 840 rental expense was $35 million and $27 million during the years ended December 31, 2018 and 2017, respectively.

As of December 31, 2018, the Partnership had the following future minimum payments for operating lease obligations as follows:

	Year Ended December 31,				
	2019	**2020-2021**	**2022-2023**	**After 2023**	**Total**
			(In millions)		
Noncancellable operating leases	$ 14	$ 6	$ 6	$ 14	$ 40

(5) Acquisitions

EOCS 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. The acquisition was accounted for as a business combination and was funded with borrowings under the commercial paper program. During the fourth quarter of 2018, the Partnership finalized the purchase price allocation as of November 1, 2018.

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

Purchase price allocation (in millions):	
Assets acquired:	
Cash	$ 1
Current Assets	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 reportable 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 were 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.

ETGP Acquisition

On October 4, 2017, the Partnership acquired all of the equity interests in Align Midstream, LLC, now ETGP, 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 reportable 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.

(6) Earnings Per Limited Partner Unit

Basic and diluted earnings per limited partner unit is calculated by dividing net income allocable to common and subordinated units 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 19 was $0.01 per unit during the years ended December 31, 2019 and 2018 and less than $0.01 per unit during the year ended December 31, 2017.

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

	Year Ended December 31,		
	2019	2018	2017
	(In millions, except per unit data)		
Net income	$ 400	$ 523	$ 437
Net income attributable to noncontrolling interests	4	2	1
Series A Preferred Unit distributions	36	36	36
General partner interest in net income	—	—	—
Net income available to common and subordinated units	$ 360	$ 485	$ 400
Net income allocable to common units	$ 360	$ 485	$ 273
Net income allocable to subordinated units	—	—	127
Net income available to common and subordinated units	$ 360	$ 485	$ 400
Net income allocable to common units	$ 360	$ 485	$ 273
Dilutive effect of Series A Preferred Unit distribution	—	—	—
Diluted net income allocable to common units	360	485	273
Diluted net income allocable to subordinated units	—	—	127
Total	$ 360	$ 485	$ 400
Basic weighted average number of outstanding			
Common units [(1)]	436	434	296
Subordinated units	—	—	137
Total	436	434	433
Basic earnings per unit			
Common units	$ 0.83	$ 1.12	$ 0.92
Subordinated units	$ —	$ —	$ 0.93
Basic weighted average number of outstanding common units [(1)]	436	434	296
Dilutive effect of Series A Preferred Units	—	—	—
Dilutive effect of performance units	1	2	1
Diluted weighted average number of outstanding common units	437	436	297
Diluted weighted average number of outstanding subordinated units	—	—	137
Total	437	436	434
Diluted earnings per unit			
Common units	$ 0.82	$ 1.11	$ 0.92
Subordinated units	$ —	$ —	$ 0.93

(1) Basic weighted average number of outstanding common units for the years ended December 31, 2019, 2018, and 2017 includes approximately one million time-based phantom units.

See Note 7 for discussion of the expiration of the subordination period.

(7) Partners’ Equity

The Partnership Agreement requires that, within 60 days after 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 2019, 2018 and 2017 (in millions, except for per unit amounts):

Quarter Ended	Record Date	Payment Date	Per Unit Distribution	Total Cash Distribution
2019				
December 31, 2019 (1)	February 18, 2020	February 25, 2020	$ 0.3305	$ 144
September 30, 2019	November 19, 2019	November 26, 2019	$ 0.3305	$ 144
June 30, 2019	August 20, 2019	August 27, 2019	$ 0.3305	$ 144
March 31, 2019	May 21, 2019	May 29, 2019	$ 0.318	$ 138
2018				
December 31, 2018	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

(1) The Board of Directors declared a $0.3305 per common unit cash distribution on February 7, 2020, to be paid on February 25, 2020, to common unitholders of record at the close of business on February 18, 2020.

The Partnership paid or has authorized payment of the following cash distributions to holders of the Series A Preferred Units during 2019, 2018, and 2017 (in millions, except for per unit amounts):

Quarter Ended	Record Date	Payment Date	Per Unit Distribution	Total Cash Distribution
2019				
December 31, 2019 [(1)]	February 7, 2020	February 14, 2020	$ 0.625	$ 9
September 30, 2019	November 5, 2019	November 14, 2019	$ 0.625	$ 9
June 30, 2019	August 2, 2019	August 14, 2019	$ 0.625	$ 9
March 31, 2019	April 29, 2019	May 15, 2019	$ 0.625	$ 9
2018				
December 31, 2018	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

(1) The Board of Directors declared a $0.625 per Series A Preferred Unit cash distribution on February 7, 2020, to be paid on February 14, 2020 to Series A Preferred unitholders of record at the close of business on February 7, 2020.

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

The Partnership has 14,520,000 Series A Preferred Units, representing limited partner interests in the Partnership, which were issued at a price of $25.00 per Series A Preferred Unit.

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 February 18, 2021, 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. Following changes of control or certain fundamental transactions, the Partnership (or a third-party with its prior written consent) may redeem the Series A Preferred Units. 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. If under certain circumstances the Series A Preferred Units are not eligible for trading on the New York Stock Exchange, the Series A Preferred Units are required to be redeemed by the Partnership.

In addition, the Partnership (or a third-party with its prior written consent) may redeem the Series A Preferred Units at any time following a reduction by any of the ratings agencies in the amount of equity content attributed to the Series A Preferred Units. On July 30, 2019, S&P announced that it was reclassifying the Series A Preferred Units from having 50% equity content to having minimal equity content. S&P's announcement followed a revision of its criteria for evaluating the amount of equity credit attributable to hybrid securities. As a result the reduction of equity content attributed to the Series A Preferred Units by S&P, the Partnership may redeem the Series A Preferred Units at any time, upon not less than 30 days' nor more than 60 days' notice, at a price of $25.50 per Series A Preferred Unit plus an amount equal to all unpaid distributions thereon from the issuance date through the redemption date.

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.

At the closing of the private placement of Series A Preferred Units, the Partnership entered into a registration rights agreement with CenterPoint Energy, pursuant to which, among other things, CenterPoint Energy has 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 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, 2019, the Partnership did not sell any common units under the ATM Program. For the year ended December 31, 2018, the Partnership sold an aggregate of 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. As of December 31, 2019, approximately $197 million of common units of aggregate offering price remained available for issuance through the ATM Program.

(8) Property, Plant and Equipment

The Partnership completed a depreciation study for the Gathering and Processing and Transportation and Storage reportable segments. Effective January 1, 2019, the new depreciation rates have been applied prospectively as a change in accounting estimate. The new depreciation rates did not result in a material change in depreciation expense or results of operations.

Property, plant and equipment includes the following:

	Weighted Average Useful Lives (Years)	December 31, 2019	December 31, 2018
		(In millions)	
Property, plant and equipment, gross:			
Gathering and Processing	33	$ 8,252	$ 8,011
Transportation and Storage	39	4,778	4,740
Construction work-in-progress		131	148
Total		$ 13,161	$ 12,899
Accumulated depreciation:			
Gathering and Processing		1,252	1,063
Transportation and Storage		1,039	965
Total accumulated depreciation		2,291	2,028
Property, plant and equipment, net		$ 10,870	$ 10,871

The Partnership recorded depreciation expense of $371 million, $351 million and $335 million during the years ended December 31, 2019, 2018 and 2017, respectively.

(9) Intangible Assets, Net

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

	December 31, 2019	December 31, 2018
	(In millions)	
Customer relationships:		
Total intangible assets [(1)]	$ 840	$ 840
Accumulated amortization	239	177
Net intangible assets	$ 601	$ 663

(1) See Note 5 for discussion of the acquisition of EOCS and ETGP 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 $62 million, $47 million and $31 million during the years ended December 31, 2019, 2018 and 2017, respectively. The following table summarizes the Partnership’s expected amortization of intangible assets for each of the next five years:

	2020	2021	2022	2023	2024
			(In millions)		
Expected amortization of intangible assets	$ 62	$ 62	$ 62	$ 62	$ 62

(10) Goodwill

In the fourth quarter of 2017, as a result of the acquisition of ETGP, the Partnership recorded $12 million of goodwill associated with the Ark-La-Tex Basin reporting unit, included in the gathering and processing reportable segment. In the fourth quarter of 2018, as a result of the acquisition of EOCS, the Partnership recorded $86 million of goodwill associated with the Anadarko Basin reporting unit, included in the gathering and processing reportable segment.

The Partnership tests its goodwill for impairment annually on October 1st, or more frequently if events or changes in circumstances indicate that the carrying value of goodwill may not be recoverable. Goodwill is assessed for impairment by comparing the fair value of the reporting unit with its book value, including goodwill. During 2019, the crude oil and natural gas industry was impacted by current and forward commodity price declines. Amid such crude oil, natural gas and NGL price declines, producers have been cutting back spending and shifting their focus from emphasizing reserves growth, to increasing net cash flows and reducing outstanding debt, which consequently resulted in a decrease in rig count and in forecasted producer activity in the Anadarko Basin reporting unit during the fourth quarter of 2019. At the same time, unit prices and market multiples for midstream companies with gathering and processing operations have dropped to their lowest levels in the last three years. Due to the continuing decrease in forward commodity prices, the reduction in forecasted producer activities, the resulting decrease in our forecasted cash flows and the increase in the weighted average cost of capital, the Partnership determined that the fair value of the goodwill associated with our Anadarko Basin reporting unit would more likely than not be impaired. As a result, the Partnership performed a quantitative test for our annual goodwill impairment analysis as of October 1, 2019, and determined that the carrying value of the Anadarko Basin reporting unit exceeded its fair value and that goodwill associated with the Anadarko Basin reporting unit was completely impaired in the amount of $86 million. The impairment is included in Impairments on the Consolidated Statements of Income for the year ended December 31, 2019.

While the fair value of the Ark-La-Tex Basin reporting unit exceeded its carrying value as of December 31, 2019, a lower fair value estimate and an impairment of the Partnership’s $12 million of goodwill could result from sustained commodity 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. 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, 2017	$ 12	$ —	$ 12
EOCS Acquisition (1)	86	—	86
Balance as of December 31, 2018	$ 98	$ —	$ 98
Goodwill impairment	$ (86)	$ —	$ (86)
Balance as of December 31, 2019	$ 12	$ —	$ 12

(1) See Note 5 for further discussion.

(11) 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, 2019 and 2018. 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 the Partnership’s 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, 2019, 2018 and 2017, the Partnership billed SESH $17 million, $18 million and $17 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, 2019, 2018 and 2017.

SESH:

	Year Ended December 31,		
	2019	2018	2017
	(In millions)		
Equity in Earnings of Equity Method Affiliate	$ 17	$ 26	$ 28
Distributions from Equity Method Affiliate (1)	25	33	33

(1) Distributions from equity method affiliate includes a $17 million, $26 million and $28 million return on investment and a $8 million, $7 million and $5 million return of investment for the years ended December 31, 2019, 2018 and 2017, respectively.

Summarized financial information of SESH:

	December 31,	
	2019	2018
	(In millions)	
Balance Sheets:		
Current assets	$ 49	$ 30
Property, plant and equipment, net	1,060	1,078
Total assets	$ 1,109	$ 1,108
Current liabilities	$ 30	$ 13
Long-term debt	398	397
Members' equity	681	698
Total liabilities and members' equity	$ 1,109	$ 1,108
Reconciliation:		
Investment in SESH	$ 309	$ 317
Less: Capitalized interest on investment in SESH	(1)	(1)
Add: Basis differential, net of amortization	33	33
The Partnership's share of members' equity	$ 341	$ 349

	Year Ended December 31,		
	2019	2018	2017
	(In millions)		
Income Statements:			
Revenues	$ 109	$ 112	$ 113
Operating income	50	67	72
Net income	33	50	54

(12) Debt

The following table presents the Partnership's outstanding debt as of December 31, 2019 and 2018.

	December 31, 2019			December 31, 2018		
	Outstanding Principal	Premium (Discount)(1)	Total Debt	Outstanding Principal	Premium (Discount)(1)	Total Debt
	(In millions)					
Commercial Paper	$ 155	$ —	$ 155	$ 649	$ —	$ 649
Revolving Credit Facility	—	—	—	250	—	250
2019 Term Loan Agreement	800	—	800	—	—	—
2019 Notes	—	—	—	500	—	500
2024 Notes	600	—	600	600	—	600
2027 Notes	700	(2)	698	700	(2)	698
2028 Notes	800	(5)	795	800	(6)	794
2029 Notes	550	(1)	549	—	—	—
2044 Notes	550	—	550	550	—	550
EOIT Senior Notes	250	1	251	250	7	257
Total debt	$ 4,405	$ (7)	$ 4,398	$ 4,299	$ (1)	$ 4,298
Less: Short-term debt (2)			155			649
Less: Current portion of long-term debt (3)			251			500
Less: Unamortized debt expense (4)			23			20
Total long-term debt			$ 3,969			$ 3,129

(1) Unamortized premium (discount) on long-term debt is amortized over the life of the respective debt.
(2) Short-term debt includes $155 million and $649 million of commercial paper outstanding as of December 31, 2019 and 2018, respectively.
(3) As of December 31, 2019, Current portion of long-term debt includes the $251 million outstanding balance of the EOIT Senior Notes due March 15, 2020. At December 31, 2018, Current portion of long-term debt included the $500 million outstanding balance of the 2019 Notes due May 15, 2019.
(4) As of December 31, 2019 and 2018, there was an additional $4 million and $6 million, respectively, of unamortized debt expense related to the Revolving Credit Facility included in Other 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):

2020	$ 405
2021	—
2022	800
2023	—
2024	600
Thereafter	$ 2,600

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 $155 million and $649 million outstanding under our commercial paper program at December 31, 2019 and December 31, 2018, respectively. The weighted average interest rate for the outstanding commercial paper was 2.29% as of December 31, 2019.

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. The Revolving Credit Facility is scheduled to mature on April 6, 2023, subject to an extension option, which could 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, 2019, there were no 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 designated credit ratings from S&P, Moody's and Fitch Ratings. As of December 31, 2019, 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 ratings. As of December 31, 2019, 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.

2019 Term Loan Agreement

On January 29, 2019, the Partnership entered into an unsecured term loan agreement with Bank of America, N.A., as administrative agent, and the several lenders thereto. The 2019 Term Loan Agreement has a scheduled maturity date of January 29, 2022, but contains an option, which may be exercised up to two times, to extend the maturity date for an additional one-year term, subject to lender approval. The 2019 Term Loan Agreement provides that outstanding borrowings bear interest at the eurodollar rate and/or an alternate base rate, at the Partnership's election, plus an applicable margin. The applicable margin is based on the Partnership's credit ratings. The applicable margin shall equal, (1) in the case of interest rates determined by reference to the eurodollar rate, between 0.75% and 1.50% per annum and (2) in the case of interest rates determined by reference to the alternate base rate, between 0% and 0.50% per annum. As of December 31, 2019, the applicable margin for LIBOR-based advances under the 2019 Term Loan Facility was 1.25% based on the Partnership's credit ratings. As of December 31, 2019, the weighted average interest rate of the 2019 Term Loan Agreement was 3.10%.

Prior to the expiration of the availability period for advances on July 26, 2019, the Partnership drew $1 billion in advances under the Term Loan Agreement, which were used for general partnership purposes and repayment of the 2019 Notes. Advances under the 2019 Term Loan Agreement can be prepaid, in whole or in part, at any time without premium or penalty, other than usual and customary LIBOR breakage costs, if applicable. On September 16, 2019, the Partnership prepaid $200 million of the advances under the Term Loan Agreement, the repayment of which was not subject to LIBOR breakage costs. As of December 31, 2019, there was $800 million outstanding under the 2019 Term Loan Agreement.

The 2019 Term Loan Agreement contains a financial covenant requiring the Partnership to maintain a ratio of consolidated funded debt to consolidated EBITDA as of the last day of each fiscal quarter of less than or equal to 5.00 to 1.00; provided that, for a certain period time following an acquisition by the Partnership or certain of its subsidiaries with a purchase price that when combined with the aggregate purchase price for all other such acquisitions in any rolling 12-month period, is equal to or greater than $25 million, the consolidated funded debt to consolidated EBITDA ratio as of the last day of each such fiscal quarter during such period would be permitted to be up to 5.50 to 1.00.

The 2019 Term Loan Agreement also contains covenants that restrict the Partnership and certain of its 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 2019 Term Loan Agreement), restricted payments, changes in the nature of their respective business and entering into certain restrictive agreements. The 2019 Term Loan Agreement is subject to acceleration upon the occurrence of certain defaults, including, 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 judgments in excess of $100 million, and the occurrence of certain ERISA and bankruptcy events, subject, where applicable, to specified cure periods.

Senior Notes

On September 13, 2019, the Partnership completed the public offering of $550 million aggregate principal amount of its 4.150% Senior Notes due 2029. The Partnership received net proceeds of approximately $544 million, after deducting the underwriting discount and offering expenses. The net proceeds were used to repay $200 million of borrowings outstanding under the 2019 Term Loan Agreement, to repay amounts outstanding under the commercial paper program, and for general partnership purposes. The 2029 Notes had an unamortized discount of $1 million and unamortized debt expense of $5 million at December 31, 2019, resulting in an effective interest rate of 4.31% from the issue date through December 31, 2019.

As of December 31, 2019, the Partnership's debt also included the 2024 Notes, 2027 Notes, 2028 Notes and 2044 Notes, which had $7 million of unamortized discount and $18 million of unamortized debt expense at December 31, 2019, resulting in effective interest rates of 4.01%, 4.57%, 5.20% and 5.08%, respectively, during the year ended December 31, 2019. In May 2019, the Partnership's 2019 Notes matured and were paid using proceeds from the 2019 Term Loan Agreement.

The indenture governing the 2024 Notes, 2027 Notes, 2028 Notes, 2029 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, 2019, the Partnership's debt included EOIT's Senior Notes. The EOIT Senior Notes had $1 million of unamortized premium at December 31, 2019, resulting in an effective interest rate of 3.84% during the year ended December 31, 2019. 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, 2019, the Partnership and EOIT were in compliance with all of their debt agreements, including financial covenants.

(13) Derivative Instruments and Hedging Activities

The Partnership is exposed to certain risks relating to its ongoing business operations. The primary risks managed using derivative instruments are commodity price and interest rate risks. The Partnership is also exposed to credit risk in its business operations.

Commodity Price Risk

The Partnership uses forward physical contracts, commodity price swap contracts and commodity price option features to manage its commodity price risk exposures. 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 price 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 its 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, 2019 and 2018, the Partnership had no commodity derivative instruments that were designated as cash flow or fair value hedges for accounting purposes.

Interest Rate Risk

The Partnership uses interest rate swap contracts to manage its interest rate risk exposures. The Partnership recognizes its interest rate 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. The Partnership's interest rate swap contracts are designated as cash flow hedging instruments for accounting purposes. For interest rate derivative instruments designated as cash flow hedging instruments, the gain or loss on the derivative is recognized currently in Accumulated other comprehensive loss and will be reclassified to Interest expense in the same period the hedged transaction affects earnings. As of December 31, 2019, the Partnership had no interest rate derivative instruments that were designated as fair value hedges for accounting purposes. As of December 31, 2018, the Partnership had no outstanding interest rate derivative instruments.

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 to manage the Partnership's exposure to commodity price risk. 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 Not Designated as Hedging Instruments

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

As of December 31, 2019 and 2018, the Partnership had the following derivative instruments that were not designated as hedging instruments for accounting purposes:

	December 31, 2019		December 31, 2018	
	Gross Notional Volume			
	Purchases	Sales	Purchases	Sales
Natural gas— TBtu [(1)]				
Financial fixed futures/swaps	10	19	16	28
Financial basis futures/swaps	11	30	18	29
Financial swaptions [(2)]	—	2	—	1
Physical purchases/sales	—	6	—	11
Crude oil (for condensate)— MBbl [(3)]				
Financial futures/swaps	—	990	—	945
Financial swaptions [(2)]	—	225	—	30
Natural gas liquids— MBbl [(4)]				
Financial futures/swaps	2,490	2,415	270	2,535

(1) As of December 31, 2019, 86.6% of the natural gas contracts had durations of one year or less and 13.4% had durations of more than one year and less than two years. 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.

(2) 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.

(3) As of December 31, 2019, 72.8% of the crude oil (for condensate) contracts had durations of one year or less and 27.2% had durations of more than one year and less than two years. 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.

(4) As of December 31, 2019, 72.2% of the natural gas liquids contracts had durations of one year or less and 27.8% had durations of more than one year and less than two years. 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.

Derivatives Designated as Hedging Instruments

Derivative instruments designated as hedging instruments for accounting purposes are utilized in managing the Partnership's interest rate risk exposures.

Quantitative Disclosures Related to Derivative Instruments Designated as Hedging Instruments

The derivative instruments designated as hedges for accounting purposes are interest rate derivative instruments priced on monthly interest rates.

As of December 31, 2019 and December 31, 2018, the Partnership had the following derivative instruments that were designated as hedging instruments for accounting purposes:

	December 31, 2019	December 31, 2018
	Gross Notional Value (In millions)	
Interest rate swaps	$ 300	$ —

Balance Sheet Presentation Related to Derivative Instruments

The fair value of the derivative instruments that are presented in the Partnership's Consolidated Balance Sheets at December 31, 2019 and 2018 that were not designated as hedging instruments for accounting purposes are as follows:

		December 31, 2019		December 31, 2018	
		Fair Value			
Instrument	Balance Sheet Location	Assets	Liabilities	Assets	Liabilities
		(In millions)			
Natural gas					
Financial futures/swaps	Other Current	$ 7	$ 5	$ 3	$ 5
Financial futures/swaps	Other	—	1	—	2
Physical purchases/sales	Other Current	5	—	3	—
Physical purchases/sales	Other	—	—	4	—
Crude oil (for condensate)					
Financial futures/swaps	Other Current	1	19	9	3
Financial futures/swaps	Other	—	8	2	—
Natural gas liquids					
Financial futures/swaps	Other Current	25	3	10	1
Financial futures/swaps	Other	11	2	2	—
Total gross derivatives (1)		$ 49	$ 38	$ 33	$ 11

(1) See Note 14 for a reconciliation of the Partnership's total derivatives fair value to the Partnership's Consolidated Balance Sheets as of December 31, 2019 and 2018.

The fair value of the derivative instruments that are presented in the Partnership's Consolidated Balance Sheets as of December 31, 2019 and December 31, 2018 that were designated as hedging instruments for accounting purposes are as follows:

		December 31, 2019		December 31, 2018	
		Fair Value			
Instrument	Balance Sheet Location	Assets	Liabilities	Assets	Liabilities
		(In millions)			
Interest rate swaps	Other Current	$ —	$ 1	$ —	$ —
Interest rate swaps	Other	—	2	—	—
Total gross interest rate derivatives (1)		$ —	$ 3	$ —	$ —

(1) All interest rate derivative instruments that were designated as cash flow hedges are considered Level 2 as of December 31, 2019.

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, 2019, 2018 and 2017:

	Amounts Recognized in Income		
	Year Ended December 31,		
	2019	2018	2017
	(In millions)		
Natural Gas			
Financial futures/swaps gains (losses)	$ 13	$ (8)	$ 20
Physical purchases/sales gains	2	7	9
Crude oil (for condensate)			
Financial futures/swaps (losses) gains	(41)	6	(1)
Natural gas liquids			
Financial futures/swaps gains (losses)	42	6	(9)
Total	$ 16	$ 11	$ 19

For derivatives not designated as hedges in the tables above, amounts recognized in income for the years ended December 31, 2019, 2018 and 2017 are reported in Product sales. For derivatives designated as hedges, amounts recognized in income and reported in Interest expense for the year ended December 31, 2019 were approximately zero.

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, 2019, 2018 and 2017:

	Year Ended December 31,		
	2019	2018	2017
	(In millions)		
Change in fair value of derivatives	$ (11)	$ 26	$ 28
Realized gain (loss) on derivatives	27	(15)	(9)
Gain on derivative activity	$ 16	$ 11	$ 19

Credit-Risk Related Contingent Features in Derivative Instruments

In the event Moody's or S&P 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 to third parties, 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, 2019, under these obligations, the Partnership has posted no cash collateral related to natural gas swaps and swaptions, crude oil swaps and swaptions, and NGL swaps 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. In certain situations where the Partnership's credit rating is lowered by Moody's or S&P, the Partnership could be subject to an early termination event related to certain derivative instruments, which could result in a cash settlement of the instruments at market values on the date of such early termination.

(14) 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 the NYMEX or the 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, over-the-counter WTI crude oil swaps and swaptions for condensate sales, and over-the-counter interest rate swaps traded in observable markets with less volume and transaction frequency than active markets. We consider the valuation of our interest rate derivatives as Level 2 as the primary input, the LIBOR curve, is based on quotes from an active exchange of Eurodollar futures for the same period as the future interest swap settlements.

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, 2019, 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 year ended December 31, 2019, there were no transfers between levels.

The impact to the fair value of derivatives due to credit risk is calculated using the probability of default based on S& P’s 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, 2019 and 2018:

	December 31, 2019		December 31, 2018	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(In millions)			
Debt				
Revolving Credit Facility (Level 2) [(1)]	$ —	$ —	$ 250	$ 250
2019 Term Loan Agreement (Level 2)	800	800	—	—
2019 Notes (Level 2)	—	—	500	497
2024 Notes (Level 2)	600	614	600	571
2027 Notes (Level 2)	698	698	698	642
2028 Notes (Level 2)	795	811	794	764
2029 Notes (Level 2)	549	526	—	—
2044 Notes (Level 2)	550	506	550	445
EOIT Senior Notes (Level 2)	251	252	257	256

(1) Borrowing capacity is effectively reduced by our borrowings outstanding under the commercial paper program. $155 million and $649 million of commercial paper was outstanding as of December 31, 2019 and 2018, respectively.

The fair value of the Partnership's Revolving Credit Facility, 2019 Term Loan Agreement, 2019 Notes, 2024 Notes, 2027 Notes, 2028 Notes, 2029 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). As of December 31, 2019, no material fair value adjustments or fair value measurements were required for these non-financial assets or liabilities.

Based upon review of forecasted undiscounted cash flows as of December 31, 2019, all of the asset groups were considered recoverable. Future price declines, throughput declines, contracted capacity declines, cost increases, regulatory or political environment changes and other changes in market conditions could reduce forecasted undiscounted cash flows.

Contracts with Master Netting Arrangements

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

As of December 31, 2019, the Partnership's Level 2 interest rate derivatives are recorded as liabilities with no netting adjustments. The following tables summarize the Partnership's other assets and liabilities that are measured at fair value on a recurring basis as of December 31, 2019 and December 31, 2018:

December 31, 2019	Commodity Contracts		Gas Imbalances [(1)]	
	Assets	Liabilities	Assets [(2)]	Liabilities [(3)]
	(In millions)			
Quoted market prices in active market for identical assets (Level 1)	$ 5	$ 31	$ —	$ —
Significant other observable inputs (Level 2)	44	7	14	11
Unobservable inputs (Level 3)	—	—	—	—
Total fair value	49	38	14	11
Netting adjustments	(37)	(37)	—	—
Total	$ 12	$ 1	$ 14	$ 11

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

(1) The Partnership uses the market approach to fair value its gas imbalance assets and liabilities at individual, or where appropriate an average of, current market indices applicable to the Partnership's operations, not to exceed net realizable value. There were no netting adjustments as of December 31, 2019 and 2018.

(2) Gas imbalance assets exclude fuel reserves for under retained fuel due from shippers of $21 million and $11 million at December 31, 2019 and 2018, respectively, which fuel reserves are based on the value of natural gas at the time the imbalance was created and which are not subject to revaluation at fair market value.

(3) Gas imbalance liabilities exclude fuel reserves for over retained fuel due to shippers of $8 million and $5 million at December 31, 2019 and 2018, respectively, which fuel reserves are based on the value of natural gas at the time the imbalance was created and which are not subject to revaluation at fair market value.

Changes in Level 3 Fair Value Measurements

The following tables provides a reconciliation of changes in the fair value of our Level 3 commodity contracts between the periods presented. Transfers out of Level 3 represent liabilities that were previously classified as Level 3 for which the inputs became observable for classification in Level 2. Because the activity and liquidity of commodity markets vary substantially between regions and time periods, the availability of observable inputs for substantially the full term and value of the Partnership's derivative contracts is subject to change.

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

For the year ended December 31, 2019, there were no Level 3 commodity contracts.

(15) Supplemental Disclosure of Cash Flow Information

The following table provides information regarding supplemental cash flow information:

	Year Ended December 31,		
	2019	2018	2017
	(In millions)		
Supplemental Disclosure of Cash Flow Information:			
Cash Payments:			
Interest, net of capitalized interest	$ 185	$ 148	$ 114
Income taxes, net of refunds	1	3	—
Non-cash transactions:			
Accounts payable related to capital expenditures	10	54	39
Lease liabilities arising from the application of ASC 842	45	—	—

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

	December 31,	
	2019	2018
	(In millions)	
Cash and cash equivalents	$ 4	$ 8
Restricted cash	—	14
Cash, cash equivalents and restricted cash shown in the Consolidated Statement of Cash Flows	$ 4	$ 22

As of December 31, 2018, Restricted cash included $14 million of cash collateral which was provided by a third party as credit assurance. The cash collateral was released in 2019.

(16) Related Party Transactions

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

Transportation and Storage Agreements

Transportation and Storage Agreements with CenterPoint Energy

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

The Partnership may agree to reimburse the costs that its customers incur to make required modifications for the repair and maintenance of pipelines that impact customer delivery points. For the years ended December 31, 2019 and 2018, we reimbursed CenterPoint Energy's LDCs $2 million and $1 million, respectively, in connection with receipt facility modifications that were necessitated by the repair and maintenance of our pipelines and in connection with a reimbursement associated with an unplanned pipeline outage. For the year ended December 31, 2017, we reimbursed CenterPoint Energy's LDCs $1 million in connection with receipt facility modifications that were necessitated by the repair and maintenance of our pipelines.

Transportation and Storage Agreement with OGE Energy

EOIT provides no-notice load-following transportation and storage services to four of OGE Energy's generating facilities. Service is provided to three generating facilities under a transportation agreement with a primary term of April 1, 2019 through May 1, 2024, which will remain in effect from year to year thereafter unless either party provides notice of termination to the other party at least 180 days prior to the commencement of the succeeding annual period. Service is provided to one additional generating facility in Muskogee, Oklahoma under a transportation agreement with a primary term of December 1, 2018 through December 1, 2038. EOIT has agreed to pay OGE Energy $2 million and to waive $5 million of demand fee charges as a result of damage that occurred to the Muskogee facility during commissioning as a result of the failure of certain filters on the connected transportation pipeline, which is included in the Partnership's results of operations as of December 31, 2019.

Gas Sales and Purchases Transactions

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

The Partnership's revenues from affiliated companies accounted for 6%, 5% and 5% of total revenues during the years ended December 31, 2019, 2018 and 2017, respectively. Amounts of total revenues from affiliated companies included in the Partnership's Consolidated Statements of Income are summarized as follows:

	Year Ended December 31,		
	2019	2018	2017
		(In millions)	
Gas transportation and storage service revenues — CenterPoint Energy	$ 108	$ 111	$ 110
Natural gas product sales — CenterPoint Energy	8	11	6
Gas transportation and storage service revenues — OGE Energy	41	37	35
Natural gas product sales — OGE Energy	10	4	2
Total revenues — affiliated companies	$ 167	$ 163	$ 153

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

	Year Ended December 31,		
	2019	2018	2017
		(In millions)	
Cost of natural gas purchases — CenterPoint Energy	$ —	$ 3	$ 1
Cost of natural gas purchases — OGE Energy	33	23	19
Total cost of natural gas purchases — affiliated companies	$ 33	$ 26	$ 20

Corporate services, operating lease expense and seconded employee

The Partnership receives services and support functions from each of CenterPoint Energy and OGE Energy under services agreements for an initial term that ended on April 30, 2016. The services agreements automatically extend year-to-year at the end of the initial term, unless terminated by the Partnership with at least 90 days' notice prior to the end of any extension. Additionally, the Partnership may terminate these services agreements at any time with 180 days' notice, if approved by the Board of Enable GP. The Partnership reimburses CenterPoint Energy and OGE Energy for these services up to annual caps, which for 2019 are $1 million and $1 million, respectively.

The Partnership leased office and data center space from an affiliate of CenterPoint Energy in Shreveport, Louisiana. The term of the lease was effective on October 1, 2016 and ended on December 31, 2019.

During the years ended December 31, 2019, 2018 and 2017, the Partnership had certain employees who are participants under OGE Energy's defined benefit and retiree medical plans, who will remain seconded to the Partnership, subject to certain termination rights of the Partnership and OGE Energy. The Partnership's reimbursement of OGE Energy for seconded employee costs arising out of OGE Energy's defined benefit and retiree medical plans is fixed at actual cost subject to a cap of $5 million in 2019 and thereafter, unless and until secondment is terminated.

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

	Year Ended December 31,		
	2019	2018	2017
		(In millions)	
Corporate Services — CenterPoint Energy	$ —	$ 1	$ 3
Operating Lease — CenterPoint Energy	1	1	1
Seconded Employee Costs — OGE Energy	18	29	31
Corporate Services — OGE Energy	—	1	3
Total corporate services, operating lease and seconded employee expense	$ 19	$ 32	$ 38

(17) Commitments and Contingencies

Commercial Obligations

On January 1, 2017, the Partnership entered into a 10-year gathering and processing agreement, which became effective on July 1, 2018, with an affiliate of Energy Transfer, LP for 400 MMcf/d of deliveries to the Godley Plant in Johnson County, Texas. As of December 31, 2019, the Partnership estimates the remaining associated minimum volume commitment fee to be $192 million in the aggregate. Minimum volume commitment fees are expected to be $23 million per year from 2020 through 2027 and $11 million in 2028.

On September 13, 2018, the Partnership executed a precedent agreement for the development of the Gulf Run Pipeline, an interstate natural gas transportation project. On January 30, 2019, a final investment decision was made by Golden Pass LNG, the cornerstone shipper for the LNG facility to be served by the Gulf Run Pipeline project. Subject to approval of the project by FERC, the Partnership will be required to construct a large-diameter pipeline from northern Louisiana to Gulf Coast markets. In addition, the Partnership may transfer existing EGT transportation infrastructure to the Gulf Run Pipeline. Under the precedent agreement, the Partnership estimates the cost to complete the Gulf Run Pipeline project would be as much as $500 million and the project is backed by a 20-year firm transportation service. The Gulf Run Pipeline connects natural gas producing regions in the U.S., including the Haynesville, Marcellus, Utica and Barnett shales and the Mid-Continent region. The project is expected to be placed into service in 2022.

On September 23, 2019, the Partnership entered into an agreement to sell its undivided 1/12th interest in the Bistineau Storage Facility in Louisiana for approximately $19 million. Until such time as the sale closes, the Partnership will continue to utilize this facility to provide storage services to its customers. On January 27, 2020, FERC approved the sale. The Partnership anticipates closing the sale on April 1, 2020.

Legal, Regulatory and Other Matters

The Partnership is involved in legal, environmental, tax and regulatory proceedings before various courts, regulatory commissions and governmental agencies regarding matters arising in the ordinary course of business. Some of these proceedings involve substantial amounts. The Partnership regularly analyzes current information and, as necessary, provides accruals for probable liabilities on the eventual disposition of these matters. The Partnership does not expect the disposition of these matters to have a material adverse effect on its financial condition, results of operations or cash flows.

(18) Income Taxes

The Partnership's earnings are generally not subject to income tax (other than Texas state margin taxes and taxes associated with the Partnership's corporate subsidiary Enable Midstream Services) and are taxable at the individual partner level. The Partnership and its non-corporate subsidiaries are pass-through entities for federal income tax purposes. For these entities, all income, expenses, gains, losses and tax credits generated flow through to their owners and, accordingly, do not result in a provision for income taxes in the consolidated financial statements. Consequently, the Consolidated Statements of Income do not include an income tax provision (other than Texas state margin taxes and taxes associated with the Partnership's corporate subsidiary). On December 22, 2017, the act known as the "Tax Cuts and Jobs Act," was signed into law which lowered the corporate tax rate from 35% to 21% for tax years beginning after December 31, 2017. As a result of this new law, the Partnership's corporate subsidiaries re-valued their deferred income tax assets and liabilities as of December 31, 2017, which resulted in recording a federal deferred income tax benefit of $1 million for the year ended December 31, 2017.

The items comprising income tax expense are as follows:

	Year Ended December 31,		
	2019	2018	2017
		(In millions)	
Provision for current income taxes			
Federal	$ —	$ —	$ 1
State	—	—	1
Total provision for current income taxes	—	—	2
Benefit for deferred income taxes, net			
Federal	$ (1)	$ (1)	$ (2)
State	—	—	(1)
Total benefit for deferred income taxes, net	(1)	(1)	(3)
Total income tax benefit	$ (1)	$ (1)	$ (1)

The components of Deferred Income Taxes as of December 31, 2019 and 2018 were as follows:

	December 31,	
	2019	2018
	(In millions)	
Deferred tax liabilities, net:		
Non-current:		
Intercompany management fee	$ 17	$ 16
Depreciation	6	5
Accrued compensation	(19)	(16)
Total deferred tax liabilities, net	$ 4	$ 5

Uncertain Income Tax Positions

There were no unrecognized tax benefits as of December 31, 2019, 2018 and 2017.

Tax Audits and Settlements

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

(19) Equity-Based Compensation

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

The LTIP is administered by the Compensation Committee of the Board of Directors. With respect to any grant of equity as long-term incentive awards to our independent directors and our officers subject to reporting under Section 16 of the Exchange Act, the Compensation Committee makes recommendations to the Board of Directors and any such awards will only be effective upon the approval of the Board of Directors. The LTIP limits the number of units that may be delivered pursuant to vested awards to 13,100,000 common units, subject to proportionate adjustment in the event of unit splits and similar events. Common units cancelled, forfeited, expired or cash settled are available for delivery pursuant to other awards.

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

Performance unit, restricted unit and phantom unit awards are classified as equity on the Partnership’s Consolidated Balance Sheet. The following table summarizes the Partnership’s equity-based compensation expense for the years ended December 31, 2019, 2018 and 2017 related to performance units, restricted units and phantom units for the Partnership’s employees and independent directors:

	Year Ended December 31,		
	2019	2018	2017
		(In millions)	
Performance units	$ 9	$ 9	$ 10
Restricted units	—	1	2
Phantom units	7	6	3
Total equity-based compensation expense	$ 16	$ 16	$ 15

Performance Units

Awards of performance based phantom units (performance units) have been made under the LTIP in 2019, 2018 and 2017 to certain officers and employees providing services to the Partnership. Subject to the achievement of performance goals, the performance unit awards cliff vest three years from the grant date, with distribution equivalent rights paid at vesting. The performance goals for 2019, 2018 and 2017 awards are based on total unitholder return over a three-calendar year performance cycle. Total unitholder return is based on the relative performance of the Partnership's common units against a peer group. The performance unit awards have a payout from zero to 200% of the target based on the level of achievement of the performance goal. Performance unit awards are paid out in common units, with distribution equivalent rights paid in cash at vesting. Any unearned performance units are cancelled. Pay out requires the confirmation of the achievement of the performance level by the Compensation Committee. Prior to vesting, performance units are subject to forfeiture if the recipient's employment with the Partnership is terminated for any reason other than death, disability, retirement or termination other than for cause within two years of a change in control. In the event of retirement, a participant will receive a prorated payment based on the target performance or a prorated payment based on the actual performance of the performance goals during the award cycle, based on the grant year.

The fair value of each performance unit award was estimated on the grant date using a lattice-based valuation model. The valuation information factored into the model includes the expected distribution yield, expected price volatility, risk-free interest rate and the probable outcome of the market condition over the expected life of the performance units. Equity-based compensation expense for each performance unit award is a fixed amount determined at the grant date fair value and is recognized over the three-year award cycle regardless of whether performance units are awarded at the end of the award cycle. Distributions are accumulated and paid at vesting and, therefore, are included in the fair value calculation of the performance unit award. The expected price volatility for the awards granted in 2019, 2018 and 2017 is based on three years of daily stock price observations, to determine the total unitholder return ranking. The risk-free interest rate for the performance unit grants is based on the three-year U.S. Treasury yield curve in effect at the time of the grant. There are no post-vesting restrictions related to the Partnership's performance units.

The number of performance units granted based on total unitholder return and the assumptions used to calculate the grant date fair value of the performance units based on total unitholder return are shown in the following table.

	2019	2018	2017
Number of units granted	638,798	551,742	468,626
Fair value of units granted	$ 19.95	$ 17.70	$ 19.27
Expected price volatility	34.2%	44.2%	47.3%
Risk-free interest rate	2.54%	2.36%	1.57%
Distribution yield	8.38%	8.56%	9.10%
Expected life of units (in years)	3	3	3

Phantom Units

Awards of phantom units have been made under the LTIP in 2019, 2018 and 2017 to certain officers and employees providing services to the Partnership. Except for Phantom units granted to retirement eligible employees, which vest in annual tranches, phantom units cliff-vest on the first, second or third anniversary of the grant date with distribution equivalent rights paid during the vesting period. Phantom unit awards are paid out in common units, with distribution equivalent rights paid in cash. Any unearned phantom units are cancelled. Prior to vesting, phantom units are subject to forfeiture if the recipient's employment with the Partnership is terminated for any reason other than death, disability, retirement or termination other than for cause within two years of a change in control.

The fair value of the phantom units was based on the closing market price of the Partnership's common unit on the grant date. Equity-based compensation expense for the phantom unit is a fixed amount determined at the grant date fair value and is recognized as services are rendered by employees over the vesting period. Distributions on phantom units are paid during the vesting period and, therefore, are included in the fair value calculation. The expected life of the phantom unit is based on the applicable vesting period. The number of phantom units granted and the grant date fair value are shown in the following table.

	2019	2018	2017
Phantom units granted	695,486	546,708	392,338
Fair value of phantom units granted	$8.95 - $15.04	$13.74 - $17.00	$15.44 - $16.93

Other Awards

In 2019, 2018 and 2017, the Board of Directors granted common units to the independent directors of Enable GP, for their service as directors, which vested immediately. The fair value of the common units was based on the closing market price of the Partnership's common unit on the grant date.

	2019	2018	2017
Common units granted	28,221	16,335	16,653
Fair value of common units granted	$ 10.43	$ 14.94	$ 15.03

Units Outstanding

A summary of the activity for the Partnership's performance units and phantom units as of December 31, 2019 and changes during 2019 are shown in the following table.

	Performance Units		Phantom Units	
	Number of Units	Weighted Average Grant-Date Fair Value, Per Unit	Number of Units	Weighted Average Grant-Date Fair Value, Per Unit
	(In millions, except unit data)			
Units outstanding at 12/31/2018	2,109,835	$ 14.33	1,447,590	$ 12.38
Granted [(1)]	638,798	19.95	695,486	14.26
Vested [(2)(3)]	(1,174,597)	11.09	(608,755)	8.71
Forfeited	(180,707)	18.96	(141,761)	14.89
Units outstanding at 12/31/2019	1,393,329	19.04	1,392,560	14.65
Aggregate intrinsic value of units outstanding at December 31, 2019	$ 14		$ 14	

(1) For performance units, this represents the target number of performance units granted. The actual number of performance units earned, if any, is dependent upon performance and may range from 0% to 200% of the target.

(2) Performance units vested as of December 31, 2019 include 1,097,846 and 26,986 units from 2016 grants, which were approved by the Board of Directors in 2016 and paid out at 200%, or 2,195,692 units on March 1, 2019 and 53,972 units on September 6, 2019, based on the level of achievement of a performance goal established by the Board of Directors over the performance period of January 1, 2016 through December 31, 2018.

(3) Performance units outstanding as of December 31, 2019 include 378,109 units from the 2017 annual grants, which were approved by the Board of Directors in 2017 and, based on the level of achievement of a performance goal established by the Board of Directors over a performance period of January 1, 2017 through December 31, 2019, will not vest. The decrease in outstanding units for a payout percentage of an amount other than 100% is not reflected above until the vesting date.

A summary of the Partnership's performance, restricted and phantom units' aggregate intrinsic value (market value at vesting date) and fair value of units vested (market value at date of grant) for each of the years ended December 31, 2019, 2018 and 2017 are shown in the following tables.

	Year Ended December 31, 2019		
	Performance Units	Restricted Stock	Phantom Units
	(In millions)		
Aggregate intrinsic value of units vested	$ 34	$ —	$ 9
Fair value of units vested	13	—	5

	Year Ended December 31, 2018		
	Performance Units	Restricted Stock	Phantom Units
		(In millions)	
Aggregate intrinsic value of units vested	$ 11	$ 3	$ 1
Fair value of units vested	7	4	—

	Year Ended December 31, 2017		
	Performance Units	Restricted Stock	Phantom Units
		(In millions)	
Aggregate intrinsic value of units vested	$ 5	$ 2	$ —
Fair value of units vested	10	4	—

Unrecognized Compensation Expense

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

	December 31, 2019	
	Unrecognized Compensation Cost (In millions)	Weighted Average to be Recognized (In years)
Performance Units	$ 12	1.32
Phantom Units	9	1.24
Total	$ 21	

As of December 31, 2019, there were 6,353,205 units available for issuance under the long-term incentive plan.

(20) Reportable Segments

The Partnership's determination of reportable segments considers the strategic operating units under which it manages sales, allocates resources and assesses performance of various products and services to wholesale or retail customers in differing regulatory environments. The accounting policies of the reportable segments are the same as those described in the summary of significant accounting policies described in Note 1. The Partnership uses operating income as the measure of profit or loss for its reportable segments.

The Partnership's assets and operations are organized into two reportable segments: (i) gathering and processing and (ii) transportation and storage. The gathering and processing segment primarily provides natural gas and crude oil gathering and natural gas processing services to our producer customers. The transportation and storage segment provides interstate and intrastate natural gas pipeline transportation and storage services primarily to our producer, power plant, LDC and industrial end-user customers.

Financial data for reportable segments are as follows:

Year Ended December 31, 2019	Gathering and Processing	Transportation and Storage [(1)]	Eliminations	Total
	(In millions)			
Product sales	$ 1,449	$ 487	$ (403)	$ 1,533
Service revenues	889	551	(13)	1,427
Total Revenues	2,338	1,038	(416)	2,960
Cost of natural gas and natural gas liquids, excluding depreciation and amortization shown separately	1,203	491	(415)	1,279
Operation and maintenance, General and administrative	320	207	(1)	526
Depreciation and amortization	308	125	—	433
Impairments	86	—	—	86
Taxes other than income tax	41	26	—	67
Operating Income	$ 380	$ 189	$ —	$ 569
Total Assets	$ 9,739	$ 5,886	$ (3,359)	$ 12,266
Capital expenditures	$ 314	$ 118	$ —	$ 432

Year Ended December 31, 2018	Gathering and Processing	Transportation and Storage [(1)]	Eliminations	Total
	(In millions)			
Product sales	$ 2,016	$ 625	$ (535)	$ 2,106
Service revenues	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
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
Total Assets	$ 9,874	$ 5,805	$ (3,235)	$ 12,444
Capital expenditures, including acquisitions	$ 981	$ 190	$ —	$ 1,171

Year Ended December 31, 2017	Gathering and Processing	Transportation and Storage [(1)]	Eliminations	Total
	(In millions)			
Product sales	$ 1,538	$ 621	$ (506)	$ 1,653
Service revenues	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
Operation and maintenance, General and administrative	289	179	(4)	464
Depreciation and amortization	232	134	—	366
Impairments	—	—	—	—
Taxes other than income tax	37	27	—	64
Operating Income	$ 327	$ 202	$ (1)	$ 528
Total Assets	$ 9,079	$ 5,616	$ (3,102)	$ 11,593
Capital expenditures	$ 601	$ 113	$ —	$ 714

(1) Equity in earnings of equity method affiliate is included in Other Income (Expense) on the Consolidated Statements of Income and is not included in the table above. See Note 11 for discussion regarding ownership interest in SESH and related equity earnings included in the transportation and storage reportable segment for the years ended December 31, 2019, 2018 and 2017.

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(21) Quarterly Financial Data (Unaudited)

Summarized unaudited quarterly financial data for 2019 and 2018 are as follows:

	Quarters Ended			
	March 31, 2019	June 30, 2019	September 30, 2019	December 31, 2019
	(in millions, except per unit data)			
Total Revenues	$ 795	$ 735	$ 699	$ 731
Cost of natural gas and natural gas liquids	378	317	263	321
Operating income [(1)]	165	167	175	62
Net income	123	124	133	20
Net income attributable to limited partners	122	124	132	18
Net income attributable to common units	113	115	123	9
Basic earnings per unit				
Common units	$ 0.26	$ 0.26	$ 0.28	$ 0.02
Diluted earnings per unit				
Common units	$ 0.26	$ 0.26	$ 0.28	$ 0.02

	Quarters Ended			
	March 31, 2018	June 30, 2018	September 30, 2018	December 31, 2018
	(in millions, except per unit data)			
Total Revenues	$ 748	$ 805	$ 928	$ 950
Cost of natural gas and natural gas liquids	375	444	516	484
Operating income	139	126	171	212
Net income	114	95	139	175
Net income attributable to limited partners	114	95	138	174
Net income attributable to common units	105	86	129	165
Basic earnings per unit				
Common Units	$ 0.24	$ 0.20	$ 0.30	$ 0.38
Diluted earnings per unit				
Common Units	$ 0.24	$ 0.20	$ 0.30	$ 0.38

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(1) The Partnership recorded an impairment to goodwill of $86 million during the fourth quarter related to the Anadarko Basin reporting unit, included in the gathering and processing reportable segment. See Note 10 for further information.

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

None.

Item 9A. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

Our management, with the participation of our chief executive officer and chief financial officer, has evaluated the effectiveness of our disclosure controls and procedures (as such term is defined in Rules 13a-15(e) or 15d-15(e) under the Securities Exchange Act of 1934, as amended (the "Exchange Act")) as of December 31, 2019. Based on such evaluation, our management has concluded that, as of December 31, 2019, our disclosure controls and procedures are designed and effective to ensure that information required to be disclosed in our reports filed or submitted under the Exchange Act is recorded, processed, summarized and reported within the time periods specified by the SEC's rules and forms and that information is accumulated and communicated to our management, including its principal executive officer and principal financial officer, or persons performing similar functions, as appropriate, to allow timely decisions regarding required disclosure.

In designing and evaluating our disclosure controls and procedures, management recognizes that any controls and procedures, no matter how well designed and operated, can provide only reasonable, and not absolute, assurance that the objectives of the control system will be met. In addition, the design of any control system is based in part upon certain assumptions about the likelihood of future events and the application of judgment in evaluating the cost-benefit relationship of possible controls and procedures. Because of these and other inherent limitations of control systems, there is only reasonable assurance that our controls will succeed in achieving their goals under all potential future conditions.

Management's Report on Internal Control Over Financial Reporting

Management of the Partnership is responsible for establishing and maintaining adequate internal control over financial reporting (as such term is defined in Exchange Act Rule 13a-15(f) or 15d-15(f)). The Partnership's internal control over financial reporting is a process designed under the supervision and with the participation of our principal executive and principal financial officers, and effected by the board of directors, management and other personnel, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of the consolidated financial statements in accordance with generally accepted accounting principles.

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

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

Management assessed the effectiveness of the Partnership's internal control over financial reporting as of December 31, 2019, with the participation of our principal executive and principal financial officers, based on the framework established in Internal Control—Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission, or COSO. Based on this assessment, management concluded that the Partnership maintained effective internal control over financial reporting as of December 31, 2019.

Our independently registered public accounting firm that audited our financial statements has issued an attestation report on the effectiveness of the Partnership's internal control over financial reporting.

Changes in Internal Controls

There were no changes in our internal controls over financial reporting during the quarter ended December 31, 2019, that have materially affected, or that are reasonably likely to materially affect, our internal control over financial reporting.

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 Internal Control over Financial Reporting

We have audited the internal control over financial reporting of Enable Midstream Partners, LP and subsidiaries (the "Partnership") as of December 31, 2019, based on criteria established in Internal Control- Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). In our opinion, the Partnership maintained, in all material respects, effective internal control over financial reporting as of December 31, 2019, based on criteria established in Internal Control-Integrated Framework (2013) issued by COSO.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the consolidated financial statements as of and for the year ended December 31, 2019, of the Partnership and our report dated February 19, 2020, expressed an unqualified opinion on those financial statements.

Basis for Opinion

The Partnership's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the Partnership's internal control over financial reporting based on our audit. We 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 audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

Definition and Limitations of Internal Control over Financial Reporting

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

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

/s/ DELOITTE & TOUCHE

Oklahoma City, Oklahoma
February 19, 2020

Part III

Item 10. Directors, Executive Officers and Corporate Governance

Management of the Partnership

As a limited partnership, we do not have directors or officers. Our operations and activities are managed by our general partner, Enable GP. Our general partner is not elected by our unitholders and will not be subject to re-election in the future. Our general partner is liable for all of our debts (to the extent not paid from our assets), except for indebtedness or other obligations that are made expressly non-recourse to it. Our general partner may therefore cause us to incur indebtedness or other obligations that are non-recourse to it.

The Board of Directors of our general partner oversees the management of our operations. The directors are appointed by CenterPoint Energy and OGE Energy, and our unitholders are not entitled to elect our directors or otherwise participate, directly or indirectly, in our management or operations. The Board of Directors is comprised of eight directors. CenterPoint Energy and OGE Energy have each appointed two of the directors, have jointly appointed three independent directors, and have jointly appointed our President and Chief Executive Officer as a director. The NYSE does not require us to have a majority of independent directors on the Board of Directors.

In identifying and evaluating both incumbent and new directors of the Board of Directors, CenterPoint Energy and OGE Energy assess their experience and personal characteristics against the following individual qualifications, which CenterPoint Energy and OGE Energy may modify from time to time:

- possesses appropriate skills and professional experience;
- has a reputation for integrity and other qualities;
- possesses expertise, including industry knowledge, determined in the context of the needs of the Board of Directors;
- has experience in positions with a high degree of responsibility;
- is a leader in the organizations with which he or she is affiliated;
- is diverse in terms of geography, gender, ethnicity and age;
- has the time, energy, interest and willingness to serve as a member of the Board of Directors; and
- meets such standards of independence and financial knowledge as may be required or desirable.

The officers of our general partner provide day-to-day management for our operations and activities. The officers of our general partner are appointed by the Board of Directors.

The following table identifies the current directors and executive officers of Enable GP. The business address of each of the directors and officers is provided.

Name	Age	Title
Scott M. Prochazka (1)	53	Director and Chairman
Xia Liu (1)	50	Director
Sean Trauschke (2)	52	Director
Stephen E. Merrill (2)	55	Director
Alan N. Harris (3)	66	Director
Ronnie K. Irani (3)	63	Director
Peter H. Kind (3)	63	Director
Rodney J. Sailor (3)	61	Director, President and Chief Executive Officer
John P. Laws (3)	45	Executive Vice President, Chief Financial Officer and Treasurer
Tina V. Faraca (4)	55	Senior Vice President and Chief Commercial Officer
Deanna J. Farmer (3)	54	Executive Vice President and Chief Administrative Officer
Mark C. Schroeder (4)	63	Executive Vice President, General Counsel and Chief Ethics & Compliance Officer

(1) 1111 Louisiana Street, Houston, Texas 77002
(2) 321 North Harvey, P.O. Box 321, Oklahoma City, Oklahoma 73101
(3) 499 West Sheridan Ave, Suite 1500, Oklahoma City, Oklahoma 73102
(4) 910 Louisiana Street, Houston, Texas 77002

Our directors hold office until the earlier of their death, resignation, removal or disqualification or until their successors have been elected and qualified. Officers serve at the discretion of the Board of Directors. There are no family relationships among any of our directors or executive officers.

Alan N. Harris has been a Director of our general partner since February 2015. Mr. Harris is also a Director of UGI Corporation, a holding company that, through subsidiaries and affiliates, distributes, stores, transports and markets energy products and related services, and a Director of UGI Utilities, Inc., a subsidiary of UGI Corporation that operates a natural gas distribution utility division and an electric utility division. Prior to his retirement in January 2015, Mr. Harris worked at Spectra Energy Corp. for more than 30 years and served in multiple roles with increasing responsibilities, including serving as Senior Advisor to the President and Chief Executive Officer from 2014 through January 2015. Mr. Harris has more than 35 years of experience with midstream assets and operations. Mr. Harris provides the Board with extensive knowledge of midstream assets and operations.

Ronnie K. Irani has been a Director of our general partner since March 2016. Mr. Irani is also a Director of Seven Generations Energy Ltd., an exploration and production company and President and Chief Executive Officer of RKI Energy Resources, LLC, an exploration and production company. Prior to founding RKI Energy Resources, Mr. Irani served as President and Chief Executive Officer of NewWoods Petroleum, LLC from 2015 through 2018 and founder, President and Chief Executive Officer of RKI Exploration and Production, LLC from 2005 though 2015. Mr. Irani also served as a Director of Seventy-Seven Energy, Inc. from 2014 through 2016. Mr. Irani has more than 40 years of experience in the energy industry. Mr. Irani provides the Board with expertise in exploration and production.

Peter H. Kind has been a Director of our general partner since February 2014. Mr. Kind is also a Director of the general partner of NextEra Energy Partners, LP, an owner of clean energy projects, a Director of Southwest Water Company, a privately held water company, and Executive Director of Energy Infrastructure Advocates LLC, an independent financial and strategic advisory firm. Mr. Kind is a Certified Public Accountant with more than 30 years of experience in providing corporate and investment banking services to the energy industry. Mr. Kind provides the board with financial expertise, including experience with the audit of large public energy companies.

Xia Liu has been a Director of our general partner since May 2019. Ms. Liu has also served as Executive Vice President and Chief Financial Officer of CenterPoint Energy since April 2019. Prior to joining CenterPoint Energy, Ms. Liu served as Executive Vice President, Chief Financial Officer and Treasurer of Georgia Power from October 2017 to April 2019, as Vice President, Chief Financial Officer and Treasurer of Gulf Power from July 2015 to October 2017, and as Senior Vice President and Treasurer of Southern Company during 2014 and 2015. Ms. Liu has more than 20 years of experience in the energy industry. Ms. Liu provides the Board with extensive financial experience.

Stephen E. Merrill has been a Director of our general partner since February 2016 and previously served as an alternate Director of our general partner from May 2015 to February 2016. Mr. Merrill has also served as Chief Financial Officer of OGE Energy and OG&E since September 2014. Mr. Merrill has more than 30 years of experience in the energy industry, including extensive experience with midstream assets and operations. Mr. Merrill provides the Board with financial expertise and knowledge of midstream assets and operations.

Scott M. Prochazka has been a Director of our general partner since November 2013 and Chairman of the Board of our general partner since May 2019. Mr. Prochazka has also served as a Director, President and Chief Executive Officer of CenterPoint Energy since January 2014. Mr. Prochazka has been with CenterPoint Energy for more than 19 years and has more than 30 years of experience in the energy and chemical industries. Mr. Prochazka provides the Board with extensive experience in the energy industry, including extensive experience with natural gas assets and operations.

Sean Trauschke has been a Director of our general partner since May 2013. Mr. Trauschke has also been Chairman of the Board of OGE Energy and OG&E since December 2015, Chief Executive Officer of OGE Energy and OG&E since June 2015, and President of OGE Energy and OG&E since August 2014 and July 2013, respectively. Mr. Trauschke has been with OGE Energy and OG&E for more than 10 years and has more than 30 years of experience in the energy industry. Mr. Trauschke provides the Board with extensive experience in the energy industry, including financial expertise.

Tina V. Faraca has served as Senior Vice President and Chief Commercial Officer of our general partner since November 2019. Ms. Faraca originally joined our general partner as Senior Vice President-Commercial in October 2018. Prior to joining our general partner, Ms. Faraca served as Vice President, Engineering & Construction for Spectra Energy Corp., and its successor Enbridge Inc., from May 2012 to October 2018. Ms. Faraca has over 30 years of experience in the energy industry, including experience in commercial, strategy and engineering.

Deanna J. Farmer has served as Executive Vice President and Chief Administrative Officer of our general partner since September 2014. Prior to joining our general partner, Ms. Farmer served as Vice President of Corporate Services and Chief Information Officer of the general partner of Access Midstream Partners, LP. Ms. Farmer has over 30 years of experience in the energy industry, including leadership roles in information technology, human resources and finance.

John P. Laws has served as Executive Vice President, Chief Financial Officer and Treasurer of our general partner since January 2016. Previously, Mr. Laws served as Vice President and Treasurer of our general partner from April 2014 to December 2015. Mr. Laws has over 20 years of experience in finance and over 10 years of experience in the energy industry.

Rodney J. Sailor has served as a Director, President and Chief Executive Officer of our general partner since January 2016. Previously, Mr. Sailor served as Executive Vice President and Chief Financial Officer of our general partner from May 2014 to December 2015. Mr. Sailor has over 35 years of experience in the energy industry. Mr. Sailor provides the Board with financial expertise and extensive experience in the midstream industry, including experience with both midstream assets and operations and exploration and production.

Mark C. Schroeder has served as the General Counsel of our general partner since June 2013, as Executive Vice President of our general partner since May 2014, and as Chief Ethics & Compliance Officer of our general partner since August 2019. Prior to the formation of Enable Midstream, Mr. Schroeder served as Senior Vice President and Deputy General Counsel of CenterPoint Energy. Mr. Schroeder has over 35 years of experience in the energy industry.

Board of Directors

Chairmanship

Under the limited liability company agreement of our general partner, the right to appoint the chairman of the Board of Directors rotates between CenterPoint Energy and OGE Energy every two years. Scott Prochazka currently serves as chairman of the Board of Directors and was appointed by CenterPoint Energy to serve as chairman on May 29, 2019. Mr. Prochazka's term will expire on May 29, 2021, at which time OGE Energy will have the right to appoint the next chairman. Although the Board of Directors has no policy with respect to the separation of the offices of chairman of the board and chief executive officer, we do not expect these positions to be occupied by the same individual due to the rotating chairmanship provision in the general partner's limited liability company agreement.

Board Membership

Members of the Board of Directors are appointed by CenterPoint Energy and OGE Energy. Accordingly, unlike holders of common stock in a corporation, our unitholders have only limited voting rights on matters affecting our business or governance, subject in all cases to any specific unitholder rights contained in our partnership agreement. CenterPoint Energy and OGE Energy are each entitled to appoint two directors and up to two alternate directors. Directors Scott M. Prochazka and Xia Liu were appointed by CenterPoint Energy. Directors Stephen E. Merrill and Sean Trauschke were appointed by OGE Energy. Currently, neither CenterPoint Energy nor OGE Energy has appointed any alternate directors.

Each independent director, who is required to meet the independence standards for audit committee members established by the NYSE and the Exchange Act, and any other directors are appointed by the unanimous agreement of CenterPoint Energy and OGE Energy. Directors Alan N. Harris, Ronnie K. Irani, and Peter H. Kind are independent directors.

Board Role in Risk Oversight

Our governance guidelines provide that the Board of Directors is responsible for reviewing the process for assessing the major risks facing us and the options for their mitigation. This responsibility is largely satisfied by the audit committee, which is responsible for reviewing and discussing with management and our registered public accounting firm our major risk exposures and the policies management has implemented to monitor such exposures, including our financial risk exposures and risk management policies.

Committees of the Board of Directors

Audit Committee. Peter H. Kind, Alan N. Harris and Ronnie K. Irani serve as the members of the audit committee. Mr. Kind is the current chairman of the audit committee. The Board of Directors is required to have an audit committee of at least three members who meet the independence and experience standards established by the NYSE and the Exchange Act. All of our members of the audit committee meet these independence and experience standards. In addition, Mr. Kind and Mr. Harris meet the Exchange Act definition of an audit committee financial expert. The audit committee assists the Board of Directors in its oversight of the integrity of our financial statements and our compliance with legal and regulatory requirements and corporate policies and controls. The audit committee has the sole authority to retain and terminate our independent registered public accounting firm, approve all auditing services and related fees and the terms thereof and pre-approve any non-audit services to be rendered by our independent registered public accounting firm. The audit committee is also responsible for confirming the independence and objectivity of our independent registered public accounting firm. Our independent registered public accounting firm has been given unrestricted access to the audit committee.

Conflicts Committee. Peter H. Kind, Alan N. Harris and Ronnie K. Irani serve as the members of the conflicts committee. Mr. Kind is the current chairman of the conflicts committee. The members of our conflicts committee may not be officers or employees of our general partner or directors, officers or employees of its affiliates, may not hold an ownership interest in our general partner or its affiliates other than common units or awards under any long-term incentive plan, equity compensation plan, or similar plan implemented by our general partner or the Partnership, and must meet the independence and experience standards established by the NYSE and the Exchange Act for audit committee members. All of the members of the conflicts committee meet these standards. The conflicts committee determines if the resolution of any conflict of interest referred to it by our general partner is in our best interests. There is no requirement that our general partner seek the approval of the conflicts committee for the resolution of any conflict. Any matters approved by the conflicts committee in good faith are deemed to be approved by all of our partners and not a breach by our general partner of any duties it may owe us or our unitholders. Any unitholder challenging any matter approved by the conflicts committee has the burden of proving that the members of the conflicts committee did not believe that the matter was in the best interests of the Partnership. Moreover, any acts taken or omitted to be taken in reliance upon the advice or opinions of experts such as legal counsel, accountants, appraisers, management consultants and investment bankers, where our general partner (or any members of the Board of Directors including any member of the conflicts committee) reasonably believes the advice or opinion to be within such person’s professional or expert competence, are conclusively presumed to have been done or omitted in good faith.

Compensation Committee. Alan N. Harris, Scott M. Prochazka and Sean Trauschke serve as the members of the compensation committee. The members of our compensation committee are not required to meet the independence standards established by the NYSE for compensation committee members. Mr. Harris is the current chairman of the compensation committee. The Board of Directors has delegated responsibility and authority to the board’s Compensation Committee for the compensation of our named executive officers and independent directors. For more information on the role of the Compensation Committee and compensation program for our named executive officers and independent directors, see Item 11. “Executive Compensation.”

Governance Guidelines

We have adopted Governance Guidelines to assist the Board in the exercise of its responsibilities. To promote open discussion among the non-management directors of our Board and among the independent directors of our Board, our Governance Guidelines provide that the non-management directors will meet separately in executive session periodically and that the independent directors will meet separately in executive session at least once a year. Currently, the chairman of the Board of Directors presides at the executive sessions of the non-management directors and the chairman of the audit committee presides at the executive sessions of the independent directors. The Partnership's definitions of independence are provided in the Partnership's Governance Guidelines, which are available under the "Governance" subsection of the "Investors" section of our website at www.enablemidstream.com.

Communications with the Board

Unitholders and other interested parties that wish to communicate with members of our Board of Directors, including the Chairman of the Board, the non-management directors individually or as a group, or the independent directors individually or as a group, may send correspondence to them in care of the General Counsel by mail to PO Box 24300, Oklahoma City, Oklahoma 73124-0300 or by email to gc@enablemidstream.com.

Section 16(a) Beneficial Ownership Reporting Compliance

Section 16(a) of the Exchange Act requires our directors, certain officers, persons who own more than 10 percent of a registered class of our equity securities to file reports with the SEC concerning their holdings of, and certain transactions in, our equity and derivative securities (*e.g.*, options, convertible securities and other securities that derive their value from equity securities). Based solely upon our review of copies of filings from reporting persons, we do not believe that any of our directors or officers or any persons who own more than 10 percent of a registered class of our equity securities failed to file on a timely basis all of the report required under Section 16(a) of the Exchange Act.

Code of Ethics

Our general partner has adopted a Code of Business Conduct and Ethics that applies to the directors, officers of our general partner, the Partnership, and our subsidiaries. Our general partner has also adopted a Code of Ethics for Senior Financial Officers that applies to our chief executive officer, chief financial officer, chief accounting officer, treasurer and other persons performing similar functions. We make available free of charge our Code of Business Conduct and Ethics, and Code of Ethics for Senior Financial Officers, as well as our Governance Guidelines, related party transactions policy, audit committee charter, compensation committee charter and insider trading policy under the "Governance" subsection of the "Investors" section of our website at www.enablemidstream.com.

Item 11. Executive Compensation

Compensation Discussion and Analysis

Overview

In this section, we describe and discuss the principles and policies used in setting the compensation of our named executive officers. Our named executive officers for the fiscal year ended December 31, 2019 were:

- Rodney J. Sailor, President and Chief Executive Officer,
- John P. Laws, Executive Vice President, Chief Financial Officer and Treasurer,
- Tina V. Faraca, Senior Vice President and Chief Commercial Officer,
- Deanna J. Farmer, Executive Vice President and Chief Administrative Officer and
- Mark C. Schroeder, Executive Vice President, General Counsel and Chief Ethics & Compliance Officer.

Objective and Design of Executive Compensation Program

We strive to provide compensation that is competitive, both on a total level and in individual components, both with our peers and with other likely competitors for executive talent. By competitive, we mean that total compensation and each element of compensation is within what we believe to be an appropriate range of the market level of compensation for similarly situated roles.

Our Compensation Committee bases compensation decisions on principles designed to align the interests of our named executive officers with those of our unitholders. Our overall compensation philosophy is pay for performance. We seek to motivate our named executive officers to achieve individual and business performance objectives by designing their compensation packages to align with our values, strategy, and financial results. We believe that our named executive officers should be rewarded for both the short-term and long-term success of the Partnership and, conversely, be subject to a degree of downside risk in the event that the Partnership does not achieve its performance objectives. As a result, actual compensation in a given year will vary based on our performance, and to a lesser extent, on qualitative appraisals of individual performance. We design the compensation packages for our named executive officers to have a significant percentage of their total compensation at risk, thus aligning each of our named executive officers with the short-term and long-term performance objectives of the Partnership and with the interests of our unitholders.

We maintain benefit programs for our employees, including our named executive officers, with the objective of retaining their services. Our benefits reflect competitive practices at the time the benefit programs were implemented and, in some cases, reflect our desire to maintain similar benefits treatment for all employees in similar positions. To the extent possible, we structure these programs to deliver benefits in a manner that is tax efficient to both the recipient and the Partnership. The Compensation Committee intends for its compensation design principles to protect and promote our unitholders' interests. We believe our compensation programs are consistent with best practices for sound governance.

Our Executive Compensation Program. The Compensation Committee of our Board of Directors oversees the compensation of our named executive officers, including base salary and short-term and long-term incentive awards. In addition, the Compensation Committee makes any remaining determinations with respect to compensation based upon the previous year's performance. With respect to any grant of equity as long-term incentive awards to our named executive officers, the Compensation Committee makes recommendations to the Board of Directors, but any such equity grants require the approval of the Board of Directors.

Role of Consultant. To provide advice on the form and amount of compensation for our named executive officers in 2019, our Compensation Committee engaged Mercer (US) Inc. ("Mercer"), an independent compensation consulting firm. Mercer's services included a compensation risk assessment and an analysis of 2019 base salaries, short-term incentive award targets, and long-term incentive award targets. In order to assist with the assessment of the competitiveness of our 2019 named executive officer compensation, Mercer provided market data from the following peer group companies:

Company	**Ticker**
1. Buckeye Partners LP	BPL
2. Crestwood Equity Partners LP	CEQP
3. DCP Midstream, LP	DCP
4. EnLink Midstream Partners, LP	ENLK
5. Magellan Midstream Partners, L.P.	MMP
6. ONEOK Inc.	OKE
7. MPLX LP	MPLX
8. NuStar Energy L.P.	NS
9. Spectra Energy Partners, LP	SEP
10. Summit Midstream Partners, LP	SMLP
11. SemGroup Corporation	SEMG
12. Targa Resources Corp.	TRGP
13. Western Gas Equity Partners, LP	WGP
14. The Williams Companies, Inc.	WMB

The Compensation Committee reviews and assesses the independence and performance of its consultant in accordance with applicable SEC and NYSE rules on an annual basis in order to confirm that the consultant is independent and meets all applicable regulatory requirements. Prior to its engagement for 2019, the Compensation Committee reviewed the independence of Mercer and determined that it meets all applicable regulatory requirements for independence.

Role of Executive Officers. Of our executive officers, our Chief Executive Officer, Chief Financial Officer and Chief Administrative Officer have roles in determining executive compensation policies and programs. Our Chief Executive Officer, Chief Financial Officer and Chief Administrative Officer work with business unit and functional leaders along with our internal compensation staff to provide information to the Board of Directors and the Compensation Committee to help ensure that our compensation programs support our business strategy and goals. Our Chief Executive Officer also makes preliminary recommendations for base salary adjustments and short-term and long-term incentive levels for the named executive officers other than himself.

Our Chief Executive Officer and our Chief Administrative Officer also periodically review and recommend specific Partnership performance metrics to be used in awards under our short-term and long-term incentive plans. Our Chief Executive Officer and our Chief Administrative Officer work with the various business units and functional departments to develop these metrics, which are then presented to the Compensation Committee. As noted above, the Compensation Committee makes final decisions regarding executive compensation, except with respect to awards to our executive officers under our long-term incentive plan. With respect to such awards, the Compensation Committee makes recommendations to the Board of Directors, and the Board of Directors makes final award decisions.

Elements of Compensation

The total annual direct compensation program for our named executive officers consists of three components: (1) base salary; (2) a short-term cash incentive under our short-term incentive plan, which is based on a percentage of annual base salary; and (3) equity-based grants under our long-term incentive plan, which are based on a percentage of annual base salary. Under our compensation structure, the allocation between base salary, short-term incentive and long-term incentive varies depending upon job title and responsibility levels. We consider it generally appropriate for officers with more responsibility to have a larger portion of their compensation at risk.

Base Salary. We view base salary as the foundation of total compensation. Base salary recognizes the job being performed and the value of that job in the competitive market. We design base salaries to attract and retain the executive talent necessary for our continued success and provide an element of compensation that is not at risk in order to avoid fluctuations in compensation that could distract our named executive officers from the performance of their responsibilities. Any annual adjustments to the base salaries of our named executive officers are primarily intended to reflect changes in market data or increased experience and individual contribution of the executive. We set and adjust base salaries using market data from the Compensation Committee’s consultant, and we target a reasonable range around the market median for each position, depending on the circumstances of the incumbent and the position.

Short-Term Incentives. The Enable Midstream Partners, LP Short-Term Incentive Plan applies to our officers and employees. Under our short-term incentive plan, we seek to encourage a high level of performance from our named executive officers through the establishment of predetermined Partnership goals, the attainment of which will require a high degree of competence and diligence on the part of those employees selected to participate, and which will be beneficial to us and our unitholders. We also seek to encourage a high level of performance from our named executive officers by providing for discretionary awards under our short-term incentive plan for individual performance.

The short-term incentive plan is administered by the Compensation Committee. The Compensation Committee approves the employees who will be participants for each plan year, determines the terms and conditions of awards for such participants, including any goals, determines whether goals are achieved, and whether any awards are paid. The Compensation Committee determines each named executive officer’s short-term incentive target and whether each named executive officer receives any discretionary award. Determinations regarding who will be participants, the terms and conditions of awards, and each named executive officer’s short-term incentive target are made using market data from the Compensation Committee’s consultant. Payment is made in cash no later than March 15 of the year following the plan year and may be subject to any restrictions the Compensation Committee may determine. If eligible, a participant may defer all or a portion of the payment under the deferred compensation plan.

The Compensation Committee may amend, modify, suspend or terminate the short-term incentive plan for the purpose of meeting or addressing any changes in legal requirements or for any other purpose permitted by law, except that no amendment or alteration that would adversely affect the rights of any participant under any award previously granted to such participant may be made without the consent of such participant.

Long-Term Incentives. The Enable Midstream Partners, LP Long-Term Incentive Plan applies to our officers, independent directors and employees. The purpose of awards to our named executive officers under our long-term incentive plan is to compensate the named executive officers based on the performance of our common units and their continued employment during the vesting period in order to align their long-term interests with those of our unitholders. Compensating our named executive officers for the long-term performance of our common units supports our pay for performance philosophy. The long-term incentive plan provides for the following types of awards: restricted units, phantom units, appreciations rights, option rights, cash incentive awards, performance units, distribution equivalent rights, and other awards denominated in, payable in, valued in or otherwise based on or related to common units.

The long-term incentive plan is administered by the Compensation Committee. Generally, the Compensation Committee approves the participants, determines the award types and amounts, sets the terms and conditions for awards, including performance goals, and determines whether awards are paid, including determining whether performance goals have been met. With respect to any grant of equity as long-term incentive awards to our independent directors and our executive officers subject to reporting under Section 16 of the Exchange Act, the Compensation Committee makes recommendations to the Board of Directors and any such awards will only be effective upon the approval of the Board of Directors. The compensation consultant provides market data to assist the Compensation Committee in making decisions related to the administration of the long-term incentive plan, including determinations regarding the award types, amounts, terms and conditions and goals for our named executive officers. The long-term incentive plan limits the number of units that may be delivered pursuant to vested awards to 13,100,000 common units, subject to proportionate adjustment in the event of unit splits and similar events. Common units cancelled, forfeited, expired or cash settled are available for delivery pursuant to other awards.

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

Other Compensation and Benefits. Our named executive officers were also eligible to participate in our employee benefit plans and programs, including a medical benefits plan, a 401(k) plan and a non-qualified deferred compensation plan.

Clawback Policy. In May 2016, our Compensation Committee adopted a Clawback Policy for our executive officers. The policy provides that, in the event of an accounting restatement, the Compensation Committee may, within 12 months after the date the Partnership is required to prepare the restatement, require a current or former executive officer to forfeit or return incentive-based compensation they would not have received based on the restatement if the Compensation Committee determines that the restatement was caused, in whole or in part, by a willful act or omission of the current or former executive officer. The policy applies to incentive-based compensation under our short-term incentive plan and long-term incentive plan, and to any other incentive-based compensation, granted on or after January 1, 2016.

Unit Ownership Guidelines. In August 2015, our Compensation Committee adopted Unit Ownership Guidelines for our independent directors and officers. We believe that our Unit Ownership Guidelines align the interests of our independent directors and named executive officers with the interests of our unitholders. The guidelines provide that: our Chief Executive Officer should own common units of the Partnership having a market value of five times base salary; our executive vice presidents should own common units of the Partnership having a market value of three times their respective base salaries; our senior vice presidents should own common units of the Partnership having a market value of two times their respective base salaries; and our independent directors should own common units of the Partnership having a market value of three times their respective annual base retainers. Our Compensation Committee reviews common unit ownership annually, based on the officer's current base salary or the independent director's current base retainer, and the average closing price for our common units for the previous calendar year. The guidelines were established with advice from the Compensation Committee's consultant.

In addition to units owned directly by our independent directors and officers, units owned indirectly (such as by a spouse or a trust), as well as phantom units granted under our long-term incentive plan, may be used to satisfy the ownership levels under the guidelines. The guidelines provide that our existing independent directors and officers should achieve and maintain the minimum ownership levels no later than five years from the adoption of the guidelines. The guidelines also provide that newly appointed independent directors and newly appointed or promoted officers should achieve and maintain the minimum ownership levels no later than five years from the date of appointment, hire or promotion.

Hedging Policy. As part of the Insider Trading Policy adopted by our Board of Directors, our directors, officers and certain designated employees are prohibited from engaging in forms of hedging or monetization transactions with respect to the Partnership's securities, such as prepaid variable forward contracts, equity swaps, collars and exchange funds, that allow an owner of securities to lock in much of the value of her or his holdings, often in exchange for all or part of the potential for upside appreciation in the security. These types transactions allow insiders to continue to own the securities without the full risks and rewards of the securities. When that occurs, the owner may not have the same objectives as the Partnership's other unit holders. Therefore, we have prohibited our directors, officers and certain designated employees from engaging in these types of transactions.

2019 Executive Compensation

As of December 31, 2019, the base salary, short-term incentive award targets, and long-term incentive award targets for our named executive officers were as follows:

Name	Base Salary	Short-Term Incentive Target	Long-Term Incentive Target
Rodney J. Sailor	725,004	100%	365%
John P. Laws	450,965	75%	250%
Tina V. Faraca	345,010	60%	105%
Deanna J. Farmer	368,222	70%	160%
Mark C. Schroeder	366,995	70%	160%

Base Salary. In February 2019, Mr. Sailor, Mr. Laws, Ms. Faraca, Ms. Farmer and Mr. Schroeder received base salary increases of 4.32%, 5.50%, 2.25%, 4.25%, and 4.00% respectively. These base salary increases were intended to better align the named executive officers with the market data for their roles. In November 2019, Ms. Faraca received a base salary increase of 8.85% in connection with her appointment as Senior Vice President and Chief Commercial Officer.

Short-Term Incentives. For 2019, the target amount of the short-term incentive award for each named executive officer was a percentage of actual base salary paid during 2019, with a payout ranging from 0% to 150% of the target, subject to straight-line interpolation based on the level of achievement of performance goals established by the Compensation Committee. The award may be increased or decreased at the discretion of the Compensation Committee based on the performance of the named executive officer, but the award may not exceed 200% of the named executive officer's target.

For the 2019 award, the performance goals were based 80% on financial targets and 20% on safety targets. The financial targets consisted of: (i) 50% on a distributable cash flow (DCF) target (ii) 15% on operation and maintenance (O&M) and general and administrative (G&A) expense targets, and (iii) 15% on cash return on invested capital (CROIC). The safety targets consisted of (i) 2.5% per quarter, for an overall 10% total recordable incidents (TRI) targets, which is derived from the Federal Occupational Safety and Health Act of 1970 standards for recordable injuries and illnesses (excluding hearing shifts, repetitive motion injuries, temporary labor laws, and any recordable injury resulting from a non-preventable vehicle incident), and (ii) 2.5% per quarter, for an overall 10% preventable vehicle incidents (PVI) targets, which is defined as one in which the driver failed to exercise every reasonable precaution to prevent the accident. If the TRI or PVI for any quarter includes the death of any person, regardless of whether the decedent is a Partnership employee, a person seconded to the Partnership, or a third party, then the funding for TRI and PVI will be 0% for that quarter. For each performance goal, the Compensation Committee established a minimum level of performance (at which a 50% payout would be made and below which no payout would be made), a target level of performance (at which a 100% payout would be made), and a maximum level of performance (at or above which a 150% payout would be made). The level of payout may range from 0% to 150%, subject to straight-line interpolation based on the actual performance achieved.

For the purpose of determining the level of performance achieved, the Compensation Committee reserved the right to adjust DCF for (1) any increases or decreases resulting from changes in accounting principles that become effective after December 31, 2018; (2) any increases or decreases in DCF attributable to any new federal or state laws or regulations enacted after December 31, 2018; (3) any other adjustments in DCF occurring during the 2019 plan year approved by the Committee; and (4) adjustments to reflect the effect of any acquisitions or divestitures occurring during the 2019 plan year as permitted under the plan. The Committee also reserved the right to adjust O&M and G&A for (1) increases or decreases in O&M and G&A attributable to a change in accounting principles effective after December 31, 2018; (2) any increases or decreases in O&M and G&A attributable to any new federal or state laws or regulations enacted after December 31, 2018; (3) any increases or decreases in O&M and G&A attributable to gains, losses, or impairments, except those attributable to the write down, abandonment or disposition of any assets never placed in service; (4) any other adjustments in O&M and G&A expenses occurring during the 2019 plan year approved by the Committee; and (5) adjustments to reflect the effect of any acquisitions or divestitures occurring during the 2019 plan year as permitted under the plan. The Committee also reserved the right to adjust CROIC for (1) any increases or decreases in CROIC attributable to changes in accounting principles that become effective after December 31, 2018; (2) any increases or decreases in CROIC attributable to any new federal or state laws or regulations enacted after December 31, 2018; (3) any increases or decreases in CROIC attributable to gains, losses, or impairments, except those attributable to the write down, abandonment or disposition of any assets never placed in service; (4) any other adjustments in CROIC occurring during the 2019 plan year as approved by the Committee; and (5) adjustments to reflect the effect of any acquisitions or divestitures during the 2019 plan year as permitted under the plan.

The following table shows the minimum, target, and maximum levels of performance for the performance goals set for 2019, the actual level of performance as calculated pursuant to the terms of the awards, and the percentage payout of the targeted amount based on the actual level of performance and as authorized by the Compensation Committee:

		Minimum	Target	Maximum	Actual Performance	Payout % of Target
DCF		$740 million	$775 million	$810 million	$784 million	56.20%
O&M and G&A		$540 million	$520 million	$500 million	$519 million	15.41%
CROIC		9.3%	9.6%	9.9%	9.7%	16.55%
Safety Targets						
TRI	Q1	3	2	1	7	—%
	Q2	3	2	1	3	1.25%
	Q3	3	2	1	5	—%
	Q4	3	2	1	3	1.25%
PVI	Q1	5	4	2	5	1.25%
	Q2	5	4	2	3	3.13%
	Q3	5	4	2	5	1.25%
	Q4	5	4	2	3	3.13%

The DCF actual performance is the amount reported in our 2019 financial statements. The O&M and G&A actual performance is the amount of O&M and G&A reported in our 2019 financial statements, as adjusted for any increases or decreases in O&M and G&A attributable to gains, losses, or impairments, except those attributable to the write down, abandonment or disposition of any assets never placed in service. The CROIC actual performance is the amount of Adjusted EBITDA reported in our 2019 financial statements, divided by invested capital, as adjusted for any increases or decreases in CROIC attributable to gains, losses, or impairments, except those attributable to the write down, abandonment or disposition of any assets never placed in service. Invested capital is the total partners' equity plus total debt, net of unamortized debt premium (discount) and debt expense, excluding unamortized debt expense related to the Revolving Credit Facility, reported in our 2019 financial statements.

Long-Term Incentives. On March 1, 2019, each named executive officer received a long-term incentive award, allocated 65% to performance units and 35% to phantom units, in each case with distribution equivalent rights under the long-term incentive plan that will vest on March 1, 2022, subject to the satisfaction of vesting criteria. In recognition of Ms. Faraca's promotion to Senior Vice President and Chief Commercial Officer, on December 3, 2019, Ms. Faraca received 20,449 performance units and 46,011 phantom units, in each case with distribution equivalent rights under the long-term incentive plan. Ms. Faraca's performance unit award is subject to the same terms and conditions as the performance unit awards made to our other named executive officers in 2019, and any performance units earned under this award will vest on December 3, 2022. Under Ms. Faraca's phantom unit award, 25,562 of the phantom units will vest on December 3, 2020 and 20,449 of the phantom units will vest on December 3, 2021. Our named executive officers received the following performance unit and phantom unit awards during 2019:

Name	Performance Award	Phantom Award
Rodney J. Sailor	114,063	61,419
John P. Laws	48,596	26,167
Tina V. Faraca	34,795	53,736
Deanna J. Farmer	25,394	13,675
Mark C. Schroeder	25,310	13,629

The performance units awarded in 2019 have a payout ranging from 0% to 200% of the target based on the level of achievement of a performance goal established by the Board of Directors over a performance period of January 1, 2019 through December 31, 2021. Performance units earned will be paid in the Partnership's common units, and distribution equivalent rights will be paid in cash at vesting to the extent earned.

For the awards in 2019, the performance goal was based on the relative total unitholder return (TUR) of our common units over the performance period compared to a peer group. The peer group consists of the following companies, which were in the Alerian US Midstream Energy Index at the time of selection, which may be adjusted by the Compensation Committee, as necessary, from time to time:

Company		Ticker
1.	Altus Midstream Company	ALTM
2.	Antero Midstream GP LP	AMGP
3.	CNX Midstream Partners LP	CNXM
4.	Crestwood Equity Partners LP	CEQP
5.	DCP Midstream, LP	DCP
6.	Energy Transfer LP	ET
7.	EnLink Midstream, LLC	ENLC
8.	Equitrans Midstream Corporation	ETRN
9.	Hess Midstream Partners LP	HESM
10.	MPLX LP	MPLX
11.	Noble Midstream Partners LP	NBLX
12.	ONEOK, Inc.	OKE
13.	Summit Midstream Partners, LP	SMLP
14.	Tallgrass Energy, LP	TGE
15.	Targa Resources Corp.	TRGP
16.	TC PipeLines, LP	TCP
17.	Western Gas Equity Partners, LP	WGP
18.	The Williams Companies, Inc.	WMB

The payout for the performance units will be determined as follows:

TUR Percentile	Payout (% of Target) [(1)]
90th percentile and above	200%
Above 75th percentile	151% - 199%
Above 50th percentile	101% - 150%
30th percentile and above	50% - 100%
Below 30th percentile	—%

(1) If our ranking falls between these percentages, vesting will be determined by straight-line interpolation.

Phantom units will be paid in the Partnership’s common units, and distribution equivalent rights will be paid in cash during the term of the award. The vesting of both the performance unit and phantom unit awards is contingent upon the executive’s employment with us on the vesting date. Notwithstanding the foregoing: (i) in the event the executive’s employment is terminated due to death or disability, we terminate the executive’s employment other than for cause within two years following a change in control, or the executive terminates his employment with us for good reason within two years following a change in control, the awards will vest; and (ii) in the event the executive’s employment is terminated due to retirement, performance units will vest following the conclusion of the performance period based on the number of days during the three-year vesting period that they are employed by us and adjusted for performance achievement.

For both the performance unit and phantom unit awards to our named executive officers: (i) “good reason” means a material reduction in the executive’s authority, duties or responsibilities, a decrease in the executive’s base salary by more than 10%, a decrease in the executive’s target award opportunities under our short-term incentive plan or long-term incentive plan by more than 10%; or a relocation of the executive’s primary office by more than 50 miles, and (ii) termination “for cause” means a material act or willful misconduct that is materially detrimental to the Partnership, an act of dishonesty in the performance of duties, habitual unexcused absence(s) from work, willful failure to perform duties in any material respect, gross negligence in the performance of duties resulting in material damage or injury to the Partnership or any affiliate, any felony conviction, or any other conviction involving dishonesty, fraud or breach of trust.

Executive Compensation Tables

The following table summarizes the compensation for our named executive officers for the years ended December 31, 2019, 2018 and 2017. For all our named executive officers, the table includes all compensation awarded by or paid by us during the periods specified.

Summary Compensation Table for 2019

Name and Principal Position	Year	Salary ($)	Bonus ($)	Stock Awards ($) (1)	Option Awards ($)	Non-Equity Incentive Plan Compensation ($) (2)	All Other Compensation ($) (4)	Total ($)
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(i)	(j)
Rodney J. Sailor	2019	719,235	—	3,199,299	—	715,085	1,930,912	6,564,531
President and Chief Executive Officer	2018	686,346	—	2,367,948	—	625,965	820,553	4,500,812
	2017	636,538	—	2,159,419	—	789,324	394,932	3,980,213
John P. Laws	2019	446,445	—	1,363,042	—	332,902	641,368	2,783,757
Executive Vice President, Chief Financial Officer and Treasurer	2018	414,920	—	924,700	—	283,813	186,470	1,809,903
	2017	349,529	—	742,140	—	336,463	124,267	1,552,399
Tina V. Faraca	2019	318,866	100,000 (3)	1,222,143		195,557	60,818	1,897,384
Senior Vice President and Chief Commercial Officer								
Deanna J. Farmer	2019	365,334	—	712,282	—	254,259	468,041	1,799,916
Executive Vice President and Chief Administrative Officer	2018	350,593	—	534,846	—	220,088	278,466	1,383,993
	2017	335,688	—	507,728	—	291,383	92,890	1,227,689
Mark C. Schroeder	2019	364,279	—	709,915	—	342,263	469,612	1,886,069
Executive Vice President, General Counsel and Chief Ethics & Compliance Officer	2018	350,168	—	534,355	—	219,821	280,128	1,384,472
	2017	335,094	—	506,528	—	290,867	140,693	1,273,182

(1) Amounts in this column reflect the aggregate grant date fair value amount of the Partnership equity-based unit awards granted to each named executive officer. The grant date fair value amount of performance unit awards is computed in accordance with FASB ASC Topic 718 based on the probable achievement level of the underlying performance conditions as of the grant date. Please refer to the Grants of Plan-Based Awards table for 2019 and the accompanying footnotes. Assuming achievement of the performance goals at the maximum level, the grant date fair value of the performance units granted in 2019 and included in this column would be $4,551,114 for Mr. Sailor, $1,938,980 for Mr. Laws, $1,388,320 for Ms. Faraca, $1,013,221 for Ms. Farmer, and $1,009,869 for Mr. Schroeder. Assuming achievement of the performance goals at the maximum level, the grant date fair value of the performance units granted in 2018 and included in this column would be $3,318,502 for Mr. Sailor, $1,295,888 for Mr. Laws, $749,524 for Ms. Farmer, and $748,852 for Mr. Schroeder. Assuming achievement of the performance goals at the maximum level, the grant date fair value of the performance units granted in 2017 and included in this column would be $2,969,584 for Mr. Sailor, $1,020,578 for Mr. Laws, $698,191 for Ms. Farmer, and $696,572 for Mr. Schroeder. The grant date fair value amount of phantom unit awards is computed in accordance with FASB ASC Topic 718. See Note 19 to the financial statements for a discussion of the valuation assumptions used for these awards.

(2) Amounts in this column reflect amounts earned under the Partnership's Short-Term Incentive Plan.

(3) This amount represents a discretionary bonus.

(4) The following table sets forth the elements of All Other Compensation for 2019, 2018 and 2017.

Name		401(k) Plan Employer Contributions ($)	Non-Qualified Matching Contributions ($)	Distribution Equivalent Rights ($)	Supplemental Life Insurance ($)	Long Term Disability ($)	Other ($) (5)	Total ($)
Rodney J. Sailor	2019	30,800	117,172	1,779,485	2,735	720	—	1,930,912
	2018	30,250	132,074	655,703	1,806	720	—	820,553
	2017	29,700	118,834	243,824	1,806	768	—	394,932
John P. Laws	2019	30,800	49,528	559,698	622	720	—	641,368
	2018	30,250	52,402	102,678	420	720	—	186,470
	2017	29,700	37,381	55,998	420	768	—	124,267
Tina V. Faraca	2019	30,800	4,642	22,882	1,774	720	—	60,818
Deanna J. Farmer	2019	30,800	33,596	401,959	966	720	—	468,041
	2018	30,250	40,367	206,163	966	720	—	278,466
	2017	29,700	37,256	24,200	966	768	—	92,890
Mark C. Schroeder	2019	30,800	33,451	401,869	2,772	720	—	469,612
	2018	30,250	40,264	206,122	2,772	720	—	280,128
	2017	29,700	37,190	70,263	2,772	768	—	140,693

(5) None of our named executive officers received perquisites valued in excess of $10,000 in 2019.

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Grants of Plan-Based Awards Table for 2019

The following Grants of Plan-Based Awards Table summarizes the grants of plan-based awards made to named executive officers during 2019.

Name	Grant Date	Board Approval Date	Estimated Future Payouts Under Non-Equity Incentive Plan Awards (1)			Estimated Future Payouts Under Equity Incentive Plan Awards (2)			All Other Stock Awards: Number of Shares of Stock or Units (#) (3)	Grant Date Fair Value of Stock Awards ($) (4)
			Threshold ($)	Target ($)	Maximum ($)	Threshold (#)	Target (#)	Maximum (#)		
(a)	(b)		(c)	(d)	(e)	(f)	(g)	(h)	(i)	(l)
Rodney J. Sailor	02/13/2019	02/13/2019	359,615	719,235	1,438,470	—	—	—	—	—
	03/01/2019	02/14/2019	—	—	—	57,031	114,063	228,126	—	2,275,557
	03/01/2019	02/14/2019	—	—	—	—	—	—	61,419	923,742
John P. Laws	02/13/2019	02/13/2019	167,417	334,834	669,668	—	—	—	—	—
	03/01/2019	02/14/2019	—	—	—	24,298	48,596	97,192	—	969,490
	03/01/2019	02/14/2019	—	—	—	—	—	—	26,167	393,552
Tina V. Faraca	02/13/2019	02/13/2019	89,011	178,021	356,042	—	—	—	—	—
	03/01/2019	02/14/2019	—	—	—	7,173	14,346	28,692	—	286,203
	03/01/2019	02/14/2019	—	—	—	—	—	—	7,725	116,184
	12/03/2019	11/04/2019	—	—	—	10,224	20,449	40,898	—	407,958
	12/03/2019	11/04/2019	—	—	—	—	—	—	25,562	228,780
	12/03/2019	11/04/2019	—	—	—	—	—	—	20,449	183,019
Deanna J. Farmer	02/13/2019	02/13/2019	127,867	255,734	511,468	—	—	—	—	—
	03/01/2019	02/14/2019	—	—	—	12,697	25,394	50,788	—	506,610
	03/01/2019	02/14/2019	—	—	—	—	—	—	13,675	205,672
Mark C. Schroeder	02/13/2019	02/13/2019	127,498	254,995	509,990	—	—	—	—	—
	03/01/2019	02/14/2019	—	—	—	12,655	25,310	50,620	—	504,935
	03/01/2019	02/14/2019	—	—	—	—	—	—	13,629	204,980

(1) Amounts in columns (c), (d) and (e) of the Grants of Plan-Based Awards Table for 2019 above represent the threshold, target and maximum amounts that would be payable to named executive officers pursuant to the 2019 annual incentive awards made under the Enable Midstream Partners, LP Short-Term Incentive Plan. The Short-Term Incentive Plan was designed with a funding trigger that requires threshold performance for the plan to payout. If threshold performance is not met, no payments will be made. For each performance measure, established thresholds were set (at which 50% payout would be made), a target level of performance (at which a 100% payout would be made) and a maximum level of performance (at or above which a 150% payout would be made) based on eligible earnings. The award may be increased or decreased at the Compensation Committee's discretion based on the performance of the named executive officer, but the award may not exceed 200% of the named executive officer's target. As discussed in the Compensation Discussion and Analysis above, the amount that each executive officer will receive is dependent upon Partnership performance against DCF (50%), O&M and G&A (15%), CROIC (15%), and safety (20%) targets.

(2) Amounts in columns (f), (g) and (h) above represent awards of performance units under Enable Midstream Partners, LP Long-Term Incentive Plan. All payouts of such performance units will be made in units and any accumulated distribution equivalent rights will be paid in cash to the extent earned. Due to their variable nature, accumulated distribution equivalent rights are not disclosed in the table above. The conditions of the 2019 award provide that the executive officer will receive from 0% to 200% of the performance units awarded depending upon the Partnership's total unitholder return of a group of 18 peer companies over a performance period from January 1, 2019 through December 31, 2021. Total unit holder return includes both price appreciation and cash distributions over the performance period. Price appreciation is determined by comparing the average closing price of units of the Partnership or any company in the peer group for the 20 trading days preceding the performance period and for the last 20 trading days during the performance period. Cash distributions for the Partnership or any company in the peer group are assumed to have been reinvested in additional units on the date two days prior to the distribution record date. At the end of the performance period, the terms of these performance units provide for payout of 100% of the performance units initially granted if the Partnership's total unitholder return is at the 50th percentile of the peer group, with higher payouts for performance above the 50th percentile up to 200% of the performance units granted if total unitholder return is at or above the 90th percentile of the peer group. The terms of these performance units provide for payouts of less than 100% of the performance units granted if the Partnership's total unitholder return is below the 50th percentile of the peer group, with no payout for performance below the 30th percentile.

(3) Amounts in column (i) above represent the number of phantom unit awards granted to each of our named executive officers under the Enable Midstream Partners, LP Long-Term Incentive Plan.

(4) Amounts reflect the grant date fair value computed in accordance with FASB ASC Topic 718 based on a probable value of these awards or target value, of 100% payout. See Note 19 to the financial statements for further information.

Outstanding Equity Awards at 2019 Fiscal Year-End Table

	Unit Awards					
Name	Number of Units That Have Not Vested (#)		Market Value of Units That Have Not Vested ($)	Equity Incentive Plan Awards: Number of Unearned Units or Other Rights That Have Not Vested (#)		Equity Incentive Plan Awards: Market Value of Unearned Units or Other Rights That Have Not Vested ($)
(a)	(g)		(h)	(i)		(j)
Rodney J. Sailor	61,419	(1)	616,033	114,063	(4)	1,144,052
	50,477	(2)	506,284	93,743	(5)	940,242
	41,490	(3)	416,145	38,526	(6)	386,416
John P. Laws	26,167	(1)	262,455	48,596	(4)	487,418
	19,712	(2)	197,711	36,607	(5)	367,168
	14,259	(3)	143,018	13,240	(6)	132,797
Tina V. Faraca	7,725	(1)	77,482	14,346	(4)	143,890
	52,779	(7)	529,373	20,449	(9)	205,103
				13,537	(10)	135,776
Deanna J. Farmer	13,675	(1)	137,160	25,394	(4)	254,702
	11,402	(2)	114,362	21,173	(5)	212,365
	9,756	(3)	97,853	9,058	(6)	90,852
Mark C. Schroeder	13,629	(8)	136,699	25,310	(4)	253,859
	11,391	(2)	114,252	21,154	(5)	212,175
	9,732	(3)	97,612	9,037	(6)	90,641

(1) This amount represents a time-based phantom unit award under the Enable Midstream Partners Long-Term Incentive Plan scheduled to vest on March 1, 2022. Values were calculated based on a $10.03 closing price of the Partnership’s common units, as reported on the NYSE at December 31, 2019.

(2) This amount represents a time-based phantom unit award under the Enable Midstream Partners Long-Term Incentive Plan scheduled to vest on March 1, 2021. Values were calculated based on a $10.03 closing price of the Partnership’s common units, as reported on the NYSE at December 31, 2019.

(3) This amount represents a time-based phantom unit award under the Enable Midstream Partners Long-Term Incentive Plan scheduled to vest on March 1, 2020. Values were calculated based on a $10.03 closing price of the Partnership’s common units, as reported on the NYSE at December 31, 2019.

(4) This amount represents a performance unit award under the Enable Midstream Partners Long-Term Incentive Plan. The performance cycle began on January 1, 2019 and ends December 31, 2021. The number of units listed reflects the number of units paid at target performance. The value of the awards was calculated based on target payout of 100% and a $10.03 closing price of the Partnership’s common units, as reported on the NYSE at December 31, 2019. This award will vest on March 1, 2022.

(5) This amount represents a performance unit award under the Enable Midstream Partners Long-Term Incentive Plan. The performance cycle began on January 1, 2018 and ends December 31, 2020. The number of units listed reflects the number of units paid at target performance. The value of the awards was calculated based on target payout of 100% and a $10.03 closing price of the Partnership’s common units, as reported on the NYSE at December 31, 2019. This award will vest on March 1, 2021.

(6) This amount represents a performance unit award under the Enable Midstream Partners Long-Term Incentive Plan. The performance cycle began on January 1, 2017 and ended December 31, 2019. The number of units listed reflects the number of units paid at threshold performance. The value of the awards was calculated based on threshold payout of 50% and a $10.03 closing price of the Partnership’s common units, as reported on the NYSE at December 31, 2019. On February 13, 2020, the Compensation Committee determined that, based on the performance level attained, this award will not vest.

(7) This amount represents three time-based phantom unit awards under the Enable Midstream Partners Long-Term Incentive Plan, of which 6,768 units will vest on October 15, 2020, 25,562 units will vest on December 3, 2020, and 20,449 units will vest on December 2, 2021. Values were calculated based on a $10.03 closing price of the Partnership’s common units, as reported on the NYSE at December 31, 2019.

(8) This amount represents a time-based phantom unit award under the Enable Midstream Partners Long-Term Incentive Plan, of which 4,543 units will vest on March 1, 2020, 4,543 units will vest on March 1, 2021 and 4,543 units will vest on March 1, 2022. Values were calculated based on a $10.03 closing price of the Partnership’s common units, as reported on the NYSE at December 31, 2019.

(9) This amount represents a performance unit award under the Enable Midstream Partners Long-Term Incentive Plan. The performance cycle began on January 1, 2019 and ends December 31, 2021. The number of units listed reflects the number of units paid at target performance. The value of the award was calculated based on target payout of 100% and a $10.03 closing price of the Partnership’s common units, as reported on the NYSE at December 31, 2019. This award will vest on December 3, 2022.

(10) This amount represents a performance unit award under the Enable Midstream Partners Long-Term Incentive Plan. The performance cycle began on January 1, 2018 and ends December 31, 2020. The number of units listed reflects the number of units paid at target performance. The value of the awards was calculated based on target payout of 100% and a $10.03 closing price of the Partnership’s common units, as reported on the NYSE at December 31, 2019. This award will vest on October 15, 2021.

2019 Option Exercises and Stock Vested Table

Name	Stock Awards	
	Number of Shares Acquired on Vesting (#)	Value Realized on Vesting ($) (1)
(a)	(d)	(e)
Rodney J. Sailor	414,984 (2)	6,241,359
	51,874 (3)	780,185
John P. Laws	127,088 (2)	1,911,404
	15,887 (3)	238,940
Tina V. Faraca	6,768 (4)	72,485
Deanna J. Farmer	93,660 (2)	1,408,646
	11,708 (3)	176,088
Mark C. Schroeder	93,660 (2)	1,408,646
	11,708 (3)	176,088

(1) The value of the awards was calculated based on the closing price of the Partnership's common units, as reported on the NYSE on the date of vesting.
(2) These amounts reflect the payout of performance units granted on April 1, 2016. The units vested on March 1, 2019. Performance was based on the Partnership's total unitholder return over a period of January 1, 2016 to December 31, 2018.
(3) These amounts reflect the payout of time-based phantom units granted on April 1, 2016. The units vested on March 1, 2019.
(4) These amounts reflect the distribution of time-based phantom units granted on October 15, 2018. The units vested on October 15, 2019.

2019 Nonqualified Deferred Compensation Table

Name	Executive Contributions in Last FY ($) (1)	Registrant Contributions in Last FY ($) (2)	Aggregate Earnings in Last FY ($) (3)	Aggregate Withdrawals/Distributions ($)	Aggregate Balance at Last FYE ($) (4)
(a)	(b)	(c)	(d)	(e)	(f)
Rodney J. Sailor	—	117,172	78,245	—	587,727
John P. Laws	—	49,528	26,570	—	187,322
Tina V. Faraca	31,887	4,642	8,652	—	72,162
Deanna J. Farmer	—	33,596	22,914	—	166,396
Mark C. Schroeder	—	33,451	28,313	—	180,887

(1) The amounts disclosed in this column reflect named executive officer contributions to the plan during the fiscal year and are reported as compensation in the "Salary" column of the Summary Compensation Table.
(2) The amounts disclosed in this column reflect registrant contributions to the plan during the fiscal year and are reported as compensation in the "Non-Qualified Matching Contributions" column of the All Other Compensation Table included in footnote 4 to the Summary Compensation Table.
(3) Represents earnings on invested funds in each named executive officer's individual account. Earnings are not above-market or preferential.
(4) The amounts disclosed in this column include the aggregate balance at the end of the last completed fiscal year end of the named executive officer's account and amounts that will be credited to the named executive officer's account in February 2020 with respect to the last completed fiscal year. Of the amounts disclosed, the following amounts were reported as compensation to the named executive officer in the Summary Compensation Table for previous years: Mr. Sailor, $250,908; Mr. Laws, $89,783; Ms. Faraca, $0; Ms. Farmer, $77,623; and Mr. Schroeder, $77,454. Of the amounts disclosed, no amounts were reported as compensation to Ms. Faraca in the Summary Compensation Table for previous years because she was not a named executive officer in previous years.

The Enable Midstream Partners Deferred Compensation Plan, a nonqualified deferred compensation plan, was adopted in 2014 and, beginning in 2015, provides a tax-deferred savings plan for certain highly-compensated employees, including our named executive officers, who are selected by the Partnership and whose participation in the partnership sponsored 401(k) plan is restricted due to compensation and contribution limitations of the Internal Revenue Code. Eligible employees may voluntarily defer up to 70% of their base salary and 100% of their bonus earned under the Enable Midstream Partners, LP Short Term Incentive Plan, and nonemployee directors may voluntarily defer up to 100% of their cash director fees. In addition, the Partnership may make company matching and annual contributions on behalf of employees whose compensation is above the Internal Revenue Code's compensation limitation for 401(k) plans. Participating employees have full discretion over how their contributions to the Deferred Compensation Plan are invested among the offered investment options, and earnings on amounts contributed to the Deferred Compensation Plan are calculated in the same manner and at the same rate as earnings on actual investments. Investment options under the deferred compensation plan mirror those of the Partnership's 401(k) plan. Distributions under the deferred compensation plan are payable upon a separation of service or a "change in control" in either a lump sum or annual installment payments payable over five or ten years at the election of the applicable participant. All amounts in a participant's account are recorded in a notional account. The Partnership has established a "rabbi" trust to hold amounts that are contributed under the deferred compensation plan; however, such amounts contributed to the trust remain assets of the Partnership and subject to the claims of its creditors. For purposes of the Deferred Compensation Plan, a "change in control" is defined as a change in the ownership of the employer, a change in effective control of the employer, or a change in the ownership of a substantial portion of the assets of the employer.

Potential Payments Upon Termination or Change-in-Control

Change of Control Plan

On August 1, 2016, the Compensation Committee of the Board adopted the Enable Midstream Partners, LP Change of Control Plan to help recruit and retain executives. The change of control benefits are "double trigger," meaning the executive must experience a covered termination during the two years after a change of control. The plan provides that a covered termination occurs if an executive's employment is terminated for any reason other than death, disability, cause or resignation by the executive other than for good reason. The plan also provides that a change of control occurs if: (i) anyone, other than an affiliate of Enable GP, becomes the beneficial owner of more than 50% of the general partner interest in the Partnership; (ii) a plan of complete liquidation of Enable GP or the Partnership is approved; (iii) Enable GP or the Partnership sell or otherwise dispose of all or substantially all of its assets in one or more transactions to anyone other than an affiliate of Enable GP unless either CenterPoint and its affiliates or OGE Energy and its affiliates own at least 50% of the voting securities of the acquirer; or (iv) anyone other than Enable GP or an affiliate of Enable GP becomes the general partner of the Partnership.

The plan provides the following change of control benefits for each of our named executive officers:

- for the President and Chief Executive Officer, a lump-sum cash payment of 2.99 times his annual base salary and short-term incentive plan award target;
- for each Executive Vice President, a lump-sum cash payment of 2.0 times his or her annual base salary and short-term incentive plan award target; and
- for any other officer who is not an Executive Vice President, a lump-sum cash payment of 1.5 times his or her annual base salary and short-term incentive plan award target.

For each of our officers, the plan also provides for a lump-sum cash payment in an amount equal to his or her target bonus under the short-term incentive plan based on eligible earnings through the date of termination and cash payments for certain health and welfare and outplacement benefits. The payment of change of control benefits are subject to the executive's execution, without revocation, of a general waiver and release of claims. The plan also contains standard confidentiality, non-disparagement and non-solicitation provisions.

Long-Term Incentives

Awards to our named executive officers under our long-term incentive plan include change of control benefits. The change of control benefits are "double trigger," meaning the executive must experience a covered termination during the two years after a change of control for accelerated vesting to occur. Awards to our named executive officers under the Long-Term Incentive Plan will vest in the event: (i) we terminate the executive's employment other than for cause within two years following a change in control; or (ii) the executive terminates his or her employment for good reason within two years following a change in control. In the event of a qualifying termination following a change in control, performance unit awards will vest at the greater of target or actual performance. For more information regarding the awards to our named executive officers under our long-term incentive plan, see "Executive Compensation Tables" above.

The following table reflects the potential payments that would be made to our named executive officers under our change of control plan and our long-term incentive plan awards, assuming a termination date of December 31, 2019 and using the closing price of the Partnership's common units of $10.03 as reported on the NYSE at December 31, 2019.

Other Benefits

The named executive officers may also receive other payments upon termination or a change of control to which they were already entitled to or vested in on such date including amounts under the Deferred Compensation Plan in accordance with the terms of the plan (see “2019 Nonqualified Deferred Compensation”).

Name	Cash Severance Payment Upon Change in Control & Covered Termination ($) (1)	Short-Term Incentive Plan Payment Upon Change in Control & Covered Termination ($) (2)	Health and Welfare Benefit Payment Upon Change in Control & Covered Termination ($) (3)	Outplacement Assistance Payment Upon Change in Control & Covered Termination ($) (4)	Acceleration of Vesting Under Long-Term Incentive Plans Upon Change in Control & Covered Termination ($) (5)	Total ($)
Rodney J. Sailor	4,418,496	719,235	27,783	25,000	4,989,725	10,180,239
John P. Laws	1,621,747	334,834	36,992	25,000	1,946,645	3,965,218
Tina V. Faraca	855,788	191,319	27,744	25,000	344,044	1,443,895
Deanna J. Farmer	1,296,688	255,734	18,584	25,000	1,134,489	2,730,495
Mark C. Schroeder	1,277,426	254,995	36,992	25,000	1,131,950	2,726,363

(1) Reflects the lump-sum cash payment of the change of control benefit, plus any accrued salary and vacation. The change of control benefit for Mr. Sailor reflects 2.99 times his base salary and short-term incentive target. The change of control benefit for Mr. Laws, Ms. Farmer and Mr. Schroeder reflects 2.00 times their base salary and short-term incentive target. The change of control benefit for Ms. Faraca reflects 1.50 times her base salary and short-term incentive target.
(2) Reflects the lump-sum cash payment of each named executive officer’s target short-term incentive bonus.
(3) Reflects the lump-sum cash payment for health and welfare benefit coverage. The benefit for Mr. Sailor reflects the sum of the Employer’s portion of the annual premium for medical, dental and vision times 2.99. The benefit for Mr. Laws, Ms. Farmer and Mr. Schroeder reflects the sum of the Employer’s portion of the annual premium for medical, dental and vision times 2.00. The benefit for Ms. Faraca reflects the sum of the Employer’s portion of the annual premium for medical, dental and vision times 1.50.
(4) Reflects the lump-sum cash payment for outplacement assistance.
(5) Amounts above include the value of all unvested phantom unit awards and, if applicable, the value of any distribution equivalent rights. All performance unit awards will vest and be paid out as if the applicable performance goals had been satisfied at target levels or actual performance, whichever is greater. The amounts above include the value of all unvested performance unit awards, assuming target level payout and, if applicable, the value of any distribution equivalent rights.

Potential Severance Payments to Current Chief Executive Officer

Mr. Sailor will be offered a severance agreement that will provide a cash payment of 1.0 times his annual base salary and short-term incentive plan award target upon a termination of his employment for any reason other than death, disability, cause, or resignation other than for good reason that is not a “covered termination” under our change of control plan (described above).

The following table reflects the potential payments that would be made to Mr. Sailor if his severance agreement was effective as of December 31, 2019.

Name	Cash Severance ($) (1)	Total ($)
Rodney J. Sailor	1,450,008	1,450,008

(1) Reflects the cash payment of 1.0 times his annual base salary of $725,004 and his short-term incentive plan award target of $725,004 as of December 31, 2019.

Pay Ratio Disclosure

As mandated by the Dodd-Frank Act, Item 402(u) of Regulation S-K requires us to disclose the ratio of the compensation of our Chief Executive Officer to the total compensation of our median employee. Mr. Sailor, our Chief Executive Officer, had 2019 annual total compensation of $6,564,530. Our median employee had 2019 annual total compensation of $110,260. As a result, the ratio of Mr. Sailor’s 2019 annual total compensation to our median employee’s 2019 annual total compensation was approximately 60 to 1.

Mr. Sailor’s 2019 annual total compensation is reported in the Summary Compensation Table provided in this Form 10-K and includes the dollar value of Mr. Sailor’s base salary and bonus (cash and non-cash). Consistent with the calculation of Mr.

Sailor's 2019 annual total compensation, our median employee's 2019 annual total compensation includes the dollar value of her or his wages plus overtime and bonus (cash and non-cash).

We chose December 31, 2019 as the date to identify our median employee, and we identified our median employee using a cash compensation measure consistently applied to all employees, which included each employee's cash base salary or wages plus overtime and cash bonus paid under our short-term incentive plan. This measure consistently excluded non-cash compensation, such as non-cash bonus, and also consistently excluded certain cash compensation, such as 401(k) matching contributions. In identifying our median employee, we included both our direct employees and employees of OGE Energy that are seconded to the Partnership because OGE is an affiliated third party. The cash compensation for our direct employees was derived from our payroll records and for employees of OGE that are seconded to the Partnership was derived from OGE Energy's payroll records, in each case for the period from January 1, 2019 through December 31, 2019.

Compensation Committee Report

The Compensation Committee reviewed and discussed the Compensation Discussion and Analysis with management. Based upon this review and discussion, the Compensation Committee recommended that the Compensation Discussion and Analysis be included in the Partnership's Annual Report on Form 10-K for the fiscal year ended December 31, 2019, as filed with the Securities and Exchange Commission.

Alan N. Harris
Scott M. Prochazka
Sean Trauschke

Director Compensation

The directors of Enable GP currently are Alan N. Harris, Ronnie K. Irani, Peter H. Kind, Xia Liu, Stephen E. Merrill, Scott M. Prochazka, Rodney J. Sailor and Sean Trauschke. Messrs. Merrill and Trauschke, who serve as the representatives of OGE Energy on the Board of Directors, and Mr. Prochazka and Ms. Liu, who serve as the representatives of CenterPoint Energy on the Board of Directors, do not receive compensation for their service as directors. In addition, Mr. Sailor, who serves as President and Chief Executive Officer of Enable GP, does not receive any additional compensation for his service as director. Messrs. Harris, Irani and Kind, our "independent directors," who are not officers or employees of Enable GP and who are not representatives of either of our sponsors, received the compensation described below for their service in 2019. In addition, Enable GP's independent directors are reimbursed for out-of-pocket expenses incurred in connection with attending meetings of the Board of Directors and its committees. Each director is indemnified for his or her actions associated with being a director to the fullest extent permitted under Delaware law.

Under the director compensation program approved by the Compensation Committee for 2019, each independent director receives an annual retainer of $85,000 per year and a grant of a number of common units equal to $100,000 divided by the average closing price of our common units on the NYSE for the 20 trading days prior to the date of grant. In addition, Mr. Kind receives a fee of $10,000 per transaction referred to the Conflicts Committee as chairman of the Conflicts Committee and all other participating independent directors receive a fee of $5,000 per transaction referred to the Conflicts Committee, although no fees were paid to the Conflicts Committee in 2019. Mr. Kind, as the chairman of the Audit Committee, receives an annual retainer for his service of $15,000, and Mr. Harris, as the chairman of the Compensation Committee, receives an annual retainer for his services of $12,500.

The following table sets forth the compensation earned by the independent directors of Enable GP in 2019:

Name	Fees Earned or Paid in Cash ($)	Stock Awards ($) (1)	Option Awards ($)	Non-Equity Incentive Plan Compensation ($)	All Other Compensation ($)	Total ($)
Alan N. Harris	97,500	98,115	—	—	—	195,615
Ronnie K. Irani	85,000	98,115	—	—	—	183,115
Peter H. Kind	100,000	98,115	—	—	—	198,115

(1) Reflects the aggregate grant date fair value of 2019 unit awards computed in accordance with FASB ASC Topic 718. Awards granted to independent directors vested immediately. See Note 19 to the financial statements for further information.

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

The following table shows the beneficial ownership of units of Enable Midstream Partners, LP as of January 31, 2020 based solely on SEC filings, held by:

- each person or group of persons known by us to be a beneficial owner of 5 percent or more of the then outstanding units;
- each member of our general partner’s board of directors;
- each named executive officer of our general partner; and
- all directors and executive officers of our general partner as a group.

Percentage of common units is based on 435,206,963 common units outstanding as of January 31, 2020.

	Common units beneficially owned		Series A Preferred Units beneficially owned	
Name of beneficial owner	Number	Percentage	Number	Percentage
CenterPoint Energy, Inc. (1)(5)	233,856,623	53.7%	14,520,000	100%
OGE Energy Corp. (2)(6)	110,982,805	25.5%	—	—
Sean Trauschke (2)	17,500	*	—	—
Stephen E. Merrill (2)	560	*	—	—
Scott M. Prochazka (1)	17,500	*	—	—
Xia Liu (1)	—	*	—	—
Alan N. Harris (3)	94,296	*	—	—
Ronnie K. Irani (3)	24,789	*	—	—
Peter H. Kind (3)	40,620	*	—	—
Rodney J. Sailor (3)	633,225	*	—	—
John P. Laws (3)	170,204	*	—	—
Tina V. Faraca (4)	65,623	*	—	—
Deanna J. Farmer (3)	153,202	*	—	—
Mark C. Schroeder (4)	153,599	*	—	—
All directors and executive officers as a group (12 people)	1,371,118	*	—	—

* Less than 1%

(1) 1111 Louisiana Street, Houston, Texas 77002

(2) 321 North Harvey, P.O. Box 321, Oklahoma City, OK 73101

(3) 499 West Sheridan Ave, Suite 1500, Oklahoma City, Oklahoma 73102

(4) 910 Louisiana Street, Houston, Texas 77002

(5) Based on a Schedule 13D/A filed with the SEC pursuant to the Exchange Act on July 31, 2019. The common units reported represent the aggregated beneficial ownership by CenterPoint Energy, together with its wholly owned subsidiaries. CenterPoint Energy may be deemed to have sole voting power with respect to 233,856,623 common units. CenterPoint Energy has no shared voting or dispositive power with respect to any of the common units shown. CenterPoint Energy also holds 14,520,000 Series A Preferred Units.

(6) Based on a Schedule 13G filed with the SEC pursuant to the Exchange Act on February 11, 2015. The common units reported represent the aggregated beneficial ownership by OGE Energy Corp., together with its wholly owned subsidiaries. OGE Energy Corp. may be deemed to have sole voting power with respect to 110,982,805 common units. OGE Energy Corp. has no shared voting or dispositive power with respect to any of the common units shown.

Beneficial Ownership of General Partner Interest

CenterPoint Energy and OGE Energy collectively own our general partner. Our general partner owns a non-economic general partner interest in us and the incentive distribution rights.

Equity Compensation Plan Information

Plan Category	Number of Securities to be Issued Upon Exercise of Outstanding Options, Warrants, and Rights	Weighted-Average Price of Outstanding Options, Warrants and Rights	Number of Securities Remaining Available for Future Issuance Under Equity Compensation Plan (Excluding Securities Reflected in Column(a))
	(a)	(b)	(c)
Equity Compensation Plans Approved By Security Holders [1]	N/A	N/A	N/A
Equity Compensation Plans Not Approved By Security Holders [2]	—	—	6,353,205

(1) Our Long-Term Incentive Plan was adopted by our general partner for the benefit of our officers, directors and employees. See Item 11. "Executive Compensation-Compensation Discussion and Analysis." The plan provides for the issuance of a total of 13,100,000 common units under the plan.

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

As of December 31, 2019, CenterPoint Energy owns 233,856,623 common units, representing 53.7% of our common units, and 14,520,000 Series A Preferred Units, representing 100% of our Series A Preferred Units. As of December 31, 2019, OGE Energy owns 110,982,805 common units, representing 25.5% of our common units. Together, CenterPoint Energy and OGE Energy own an aggregate 79.2% of our common units. In addition, CenterPoint Energy owns a 50% management interest and a 40% economic interest in our general partner, and OGE Energy owns a 50% management interest and a 60% economic interest in our general partner. Enable GP, our general partner, owns the non-economic general partner interest in us and all of the incentive distribution rights from us.

Distributions and Payments to Our General Partner and Its Affiliates

The following information summarizes the distributions and payments made or to be made by us to our general partner and its affiliates in connection with our ongoing operation and any liquidation. These distributions and payments were determined by and among affiliated entities and, consequently, may not equal the distributions and payments that would result from arm's-length negotiations.

Distributions of Available Cash to Our General Partner and Its Affiliates

We generally make cash distributions to unitholders pro rata, including affiliates of our general partner as holders of an aggregate of 344,839,428 common units as of December 31, 2019. In addition, if distributions exceed the minimum quarterly distribution and other higher target levels, our general partner will be entitled to increasing percentages of the distributions, up to 50% of the distributions above the highest target level.

Payments to Our General Partner and Its Affiliates

Pursuant to the services agreements, we will reimburse CenterPoint Energy and OGE Energy and their respective affiliates for the payment of certain operating expenses and for the provision of various general and administrative services for our benefit. Please see "—Services Agreements."

Our general partner and its affiliates are entitled to reimbursement for any other expenses they incur on our behalf and any other necessary or appropriate expenses allocable to us or reasonably incurred by our general partner and its affiliates in connection with operating our business to the extent not otherwise covered by the services agreements. Our Partnership Agreement provides that our general partner will determine any such expenses that are allocable to us in good faith.

Withdrawal or Removal of Our General Partner

If our general partner withdraws or is removed, its incentive distribution rights will either be sold to the new general partner for cash or converted into common units, in each case for an amount equal to the fair market value of those interests. Please read "The Partnership Agreement—Withdrawal or Removal of the General Partner."

Liquidation

Upon our liquidation, the partners, including our general partner, will be entitled to receive liquidating distributions according to their particular capital account balances.

Transactions with CenterPoint Energy and OGE Energy

Registration Rights Related to Common Units

In connection with our IPO, the Partnership entered into a registration rights agreement with certain of our unitholders, including affiliates of CenterPoint Energy and OGE Energy. Affiliates of CenterPoint Energy and OGE Energy each have certain rights to require the Partnership to file and maintain a registration statement with respect to the resale of their common units. We are not obligated to effect more than three such demand registrations for CenterPoint Energy and OGE Energy combined. Affiliates of CenterPoint Energy and OGE Energy also each have certain rights to request to "piggyback" onto any registration statement filed by the partnership for the sale of common units by the Partnership (other than pursuant to a demand registration discussed above, or other than for an employee benefit plan) to resell their common units. We have agreed to pay certain expenses in connection with such demand and piggyback registrations and associated resales of common units, excluding any underwriting discounts, selling commissions, transfer taxes applicable to the sale of any common units and any fees and disbursements of the selling unitholder's counsel or any other advisor of the selling unitholder.

Registration Rights Related to Preferred Units

At the closing of the private placement of Series A Preferred Units, the Partnership entered into a registration rights agreement with CenterPoint Energy, pursuant to which, among other things, CenterPoint Energy has 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 partnership interests in the Partnership that are issuable upon conversion of the Series A Preferred Units.

Services Agreements

In connection with our formation, we entered into services agreements with each of CenterPoint Energy and OGE Energy pursuant to which they have provided certain administrative services to us that are generally consistent with the level and type of services they provided to each of their respective businesses prior to our formation. The initial term of the services agreements ended April 30, 2016, and the services agreements now continue on a year-to-year basis unless terminated by us at the end of any annual period with at least 90 days' notice. We may also terminate each services agreement, or the provision of any services thereunder, with the approval of our Board of Directors with at least 180 days' notice; provided, however, that the services agreement with OGE Energy, and the provision of payroll and benefit administration services thereunder, may not be terminated until the transitional seconding agreement between the Partnership and OGE Energy is terminated.

Originally, the services provided by CenterPoint Energy and OGE Energy included accounting, finance, legal, risk management, information technology, human resources, and other administrative services. Over time, we have reduced our reliance on administrative services provided by CenterPoint Energy and OGE Energy and, as a result, exercised our option to terminate most of the services provided under the services agreements. As of December 31, 2019, the services provided by CenterPoint Energy primarily consisted of the provision of certain office space and data center space, and the services provided by OGE Energy primarily consisted of payroll and benefit administration services related to the transitional seconding agreement between the Partnership and OGE Energy.

We are required to reimburse CenterPoint Energy and OGE Energy for their direct expenses or, where the direct expenses cannot reasonably be determined, an allocated cost as set forth in the agreements. Unless otherwise approved by the Board of Directors, our reimbursement obligations are capped at amounts set forth in our annual budget. Under the services agreement, we reimbursed less than $1 million to each of CenterPoint Energy and OGE Energy, respectively, for the year ended December 31, 2019.

Employee Secondment

In connection with our formation, we entered into an employee transition agreement with CenterPoint Energy and OGE Energy and a transitional seconding agreement with each of CenterPoint Energy and OGE Energy in May 2013, pursuant to which they agreed to second certain of their employees to us. The Partnership transitioned seconded employees from CenterPoint Energy and OGE Energy to the Partnership effective January 1, 2015, except for certain employees who are participants under OGE Energy's defined benefit and retiree medical plans, who remain seconded to the Partnership, subject to certain termination rights of the Partnership and OGE Energy. Each of the seconded employees works full time for us and our subsidiaries but remains employed by OGE Energy. We are required to reimburse OGE Energy for certain employment-related costs, including base salary and short and long-term compensation costs and OGE Energy's share of costs related to taxes, insurance and other benefit matters under the agreements. The Partnership's reimbursement of OGE Energy for seconded employee costs arising out of OGE Energy's defined benefit and retiree medical plans is fixed at actual cost subject to a cap of $5 million in 2019 and thereafter, unless and until secondment is terminated.

Shreveport Lease

The Partnership leases office and data center space from an affiliate of CenterPoint Energy in Shreveport, Louisiana. The term of the lease was effective on October 1, 2016 and ended on December 31, 2019. The Partnership incurred less than $1 million in rent and maintenance expenses under the lease during the year ended December 31, 2019.

Omnibus Agreement

In connection with our formation, we entered into an omnibus agreement that primarily addresses competition restrictions on CenterPoint Energy and OGE Energy. The omnibus agreement provides that 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. "Midstream operations" generally means, subject to certain exceptions, the gathering, compression, treatment, processing, blending, transportation, storage, isomerization and fractionation of crude oil and natural gas, its associated production water and enhanced recovery materials such as carbon dioxide, and its respective constituents and the following products: methane, NGLs (Y-grade, ethane, propane, normal butane, isobutane and natural gasoline), condensate, and refined products and distillates (gasoline, refined product blendstocks, olefins, naphtha, aviation fuels, diesel, heating oil, kerosene, jet fuels, fuel oil, residual fuel oil, heavy oil, bunker fuel, cokes, and asphalts).

The prohibition on CenterPoint Energy and OGE Energy either directly or indirectly, owning, operating, acquiring or investing in any business engaged in midstream operations, other than through us, is subject to the following exceptions. CenterPoint Energy or OGE Energy may acquire a business engaged in midstream operations if:

- Such party intends to cease using the midstream operations assets of the business within 12 months of the acquisition of such business; or
- Such party acquires a business with midstream operations having a value in excess of $50 million (or $100 million in the aggregate with any of such party's other midstream operations assets), and it offers to us the opportunity to acquire the midstream operations assets of such business.

Tax Sharing Agreement

In connection with our formation, we entered into a tax sharing agreement with CenterPoint Energy, OGE Energy and Enable GP on May 1, 2013 pursuant to which we agreed to reimburse them for state income and franchise taxes attributable to our activities (including the activities of our direct and indirect subsidiaries) that is reported on their state income or franchise tax returns filed on a combined or unitary basis. Our general partner is responsible for determining whether CenterPoint Energy and OGE Energy is required to include our activities on a consolidated, combined or unitary tax return. Reimbursements under the agreement equal the amount of tax that we and our subsidiaries would be required to pay if we were to file a consolidated, combined or unitary tax return separate from CenterPoint Energy or OGE Energy. We are required to pay the reimbursement within 90 days of CenterPoint Energy or OGE Energy filing the combined or unitary tax return on which our activity is included, subject to certain prepayment provisions.

Reimbursement of Expenses of Our General Partner

Our general partner does not receive any management fee or other compensation for its management of our partnership; however, our general partner is reimbursed by us for (i) all salary, bonus, incentive compensation and other amounts paid to any employee of the general partner that manages our business and (ii) all overhead and general and administrative expenses allocable to us that are incurred by the general partner. Our Partnership Agreement provides that our general partner determines the expenses that are allocable to us.

Transportation, Storage and Commodity Transactions with Affiliates of CenterPoint Energy and OGE Energy

Transportation and Storage Agreements with CenterPoint Energy

EGT provides natural gas transportation and storage services to CenterPoint Energy's LDCs in Arkansas, Louisiana, Oklahoma and Northeast Texas under a combination of contracts that include the following types of services: firm transportation, firm transportation with seasonal demand, firm storage, no-notice transportation with storage and maximum rate firm transportation. These contracts are in effect through March 31, 2021. EGT has entered into precedent agreements with CenterPoint Energy's LDCs pursuant to which these contracts are expected to be extended beyond March 31, 2021, pursuant to the terms of the approved contracts. For the year ended December 31, 2019, we recorded revenues from CenterPoint Energy's LDCs of $108 million for natural gas transportation and storage services.

We repair and maintain our transportation systems as necessary to continue the safe and reliable operations of our pipelines. From time to time, the repair and maintenance of our pipelines impacts the delivery points where our customers receive natural gas from our transportation systems. On occasion, those impacts require our customers to modify their receipt facilities in order to continue to receive natural gas from our pipelines. Under those circumstances, we may agree to reimburse the costs that our customers incur to make the required modifications. For the year ended December 31, 2019, we reimbursed CenterPoint Energy's LDCs $2 million in connection with receipt facility modifications that were necessitated by the repair and maintenance of our pipelines and in connection with a reimbursement associated with an unplanned pipeline outage.

Transportation and Storage Agreements with OGE Energy

EOIT provides no-notice load-following transportation and storage services to four of OGE Energy's generating facilities. Service is provided to three generating facilities under a transportation agreement with a primary term of April 1, 2019 through May 1, 2024, which will remain in effect from year to year thereafter unless either party provides notice of termination to the other party at least 180 days prior to the commencement of the succeeding annual period. Service is provided to one additional generating facility in Muskogee, Oklahoma under a transportation agreement with a primary term of December 1, 2018 through December 1, 2038. EOIT has agreed to pay OGE Energy $2 million and to waive $5 million of demand fee charges as a result of damage that occurred to the Muskogee facility during commissioning as a result of the failure of certain filters on the connected transportation pipeline, which is included in the Partnership's results of operations as of December 31, 2019. For the year ended December 31, 2019, we recorded revenues from OGE Energy of $41 million for natural gas transportation and storage services.

Natural Gas Sales and Purchases

From time to time, we sell natural gas volumes to affiliates of CenterPoint Energy and OGE Energy or purchase natural gas volumes from affiliates of CenterPoint Energy through a combination of forward, monthly and daily transactions. We enter into these physical natural gas transactions in the normal course of business based upon relevant market prices. In the year ended December 31, 2019, we recorded revenues of $8 million from gas sales to CenterPoint Energy and revenues of $10 million from gas sales to OGE Energy. In addition, we recorded $0 million and $33 million for costs of natural gas purchases from CenterPoint Energy and OGE Energy in the year ended December 31, 2019 respectively.

Review, Approval or Ratification of Transactions with Related Persons

The Board of Directors has adopted a related party transactions policy providing that the Board of Directors or its authorized committee will review on at least a quarterly basis all related person transactions that are required to be disclosed under SEC rules and, when appropriate, initially authorize or ratify all such transactions. In the event that the Board of Directors or its authorized committee considers ratification of a related person transaction and determines not to so ratify, the related party transactions policy will provide that our management will make all reasonable efforts to cancel or annul the transaction.

The related party transactions policy provides that, in determining whether or not to recommend the initial approval or ratification of a related person transaction, the Board of Directors or its authorized committee should consider all of the relevant facts and circumstances available, including (if applicable) but not limited to: (1) whether there is an appropriate business justification for the transaction; (2) the benefits that accrue to us as a result of the transaction; (3) the terms available to unrelated third parties entering into similar transactions; (4) the impact of the transaction on a director's independence (in the event the related person is a director, an immediate family member of a director or an entity in which a director or an immediate family member of a director is a partner, shareholder, member or executive officer); (5) the availability of other sources for comparable products or services; (6) whether it is a single transaction or a series of ongoing, related transactions; and (7) whether entering into the transaction would be consistent with the code of business conduct and ethics.

Pursuant to our related party transactions policy, the Board of Directors has authorized natural gas transportation and storage agreements with CenterPoint Energy and OGE Energy and their respective affiliates as well as natural gas sale and purchase transactions with CenterPoint Energy and OGE Energy and their respective affiliates. With respect to natural gas transportation and storage agreements, the Board of Directors has determined that because the rates, charges, and other terms for transportation and storage services are subject to regulation, the terms available to CenterPoint Energy and OGE Energy are on terms no less favorable to us than those generally provided to or available from unrelated third parties entering into similar transactions. With respect to natural gas sale and purchase transactions, the Board of Directors has determined that because there is a robust, liquid market for natural gas, with transparent price determination by market conditions with reference to indexes, the terms available to CenterPoint Energy and OGE Energy are on terms no less favorable to us than those generally provided to or available from unrelated third parties entering into similar transactions.

Many of the other related party transactions policy described above were entered into prior to the closing of our IPO and, as a result, were not reviewed under our related party transactions policy. These transactions were entered into by and among affiliated entities and, consequently, may not reflect terms that would result from arm's-length negotiations. Because some of these agreements relate to our formation and, by their nature, would not occur in a third-party situation, it is not possible to determine what the differences would be in the terms of these transactions when compared to the terms of transactions with an unaffiliated third party. We believe the terms of these agreements to be comparable to the terms of agreements used in similarly structured transactions.

Director Independence

Because we are a publicly traded partnership, the NYSE does not require our Board of Directors to have a majority of independent directors. For a discussion of the independence of our Board of Directors, please see "Item 10. Directors, Executive Officers and Corporate Governance—Management of the Partnership."

Item 14. Principal Accountant Fees and Services

We have engaged Deloitte & Touche LLP as our independent registered public accounting firm. The following table summarizes the fees we have paid Deloitte & Touche LLP to audit the Partnership's annual consolidated financial statements and for other services for each of the last two fiscal years:

	2019	2018
	(In thousands)	
Audit fees	$ 1,741	$ 2,003
Audit-related fees	237	290
Tax	179	342
Total	$ 2,157	$ 2,635

Audit fees are primarily for audit of the Partnership's consolidated financial statements and reviews of the Partnership's financial statements included in the Form 10-Qs.

Audit-related fees for the years ended December 31, 2019 and 2018, include fees associated with comfort letters issued in connection with registration statements filed by the Partnership or its affiliates.

Tax fees represent amounts we were billed in each of the years presented for professional services rendered in connection with tax compliance, tax advice and tax planning. This category primarily includes services relating to the preparation of unitholder annual K-1 statements and the preparation of U.S. federal and state income tax returns for Enable Midstream Partners, LP. These services primarily relate to the two tax years ended December 31, 2018 and 2017.

Audit Committee Approval of Audit and Non-Audit Services

The Audit Committee of the Enable GP Board of Directors is responsible for pre-approving audit and non-audit services performed by Deloitte & Touche LLP. In addition to its approval of the audit engagement, the Audit Committee takes action at least annually to authorize the independent auditor's performance of several specific types of services within the categories of audit-related services and tax services. Audit-related services include assurance and related services that are reasonably related to the performance of the audit or review of the financial statements or that are traditionally performed by the independent auditor. Tax services include compliance-related services such as services involving tax filings, as well as consulting services such as tax planning, transaction analysis and opinions. Additional services are subject to preapproval if they are outside the specific types of services included in the periodic approvals or if they are in excess of the fee limitations in the periodic approvals. The Audit Committee may delegate preapproval authority to one or more members, provided that the delegated decision must be presented to the Audit Committee at its next scheduled meeting.

The Audit Committee has approved the appointment of Deloitte & Touche LLP as our independent registered public accounting firm to conduct the audit of the Partnership's consolidated financial statements for the year ended December 31, 2019.

Part IV

Item 15. Exhibits and Financial Statement Schedules

The following exhibits are filed as part of this report:

(1) Financial Statements

The financial statements required by this Item 15(a)(1) are set forth in Item 8.

(2) Financial Statement Schedules

No schedules are required to be presented.

(3) Exhibits:

Exhibits not incorporated by reference to a prior filing are designated by a cross (+); all exhibits not so designated are incorporated by reference to a prior filing as indicated. Management contracts and compensatory plans and arrangements are designated by a star (*).

Agreements included as exhibits are included only to provide information to investors regarding their terms. Agreements listed below may contain representations, warranties and other provisions that were made, among other things, to provide the parties thereto with specified rights and obligations and to allocate risk among them, and no such agreement should be relied upon as constituting or providing any factual disclosures about Enable Midstream Partners, LP, any other persons, any state of affairs or other matters.

Exhibit Number	Description	Report or Registration Statement	SEC File or Registration Number	Exhibit Reference
2.1	Master Formation Agreement dated as of March 14, 2013 by and among CenterPoint Energy, Inc., OGE Energy Corp., Bronco Midstream Holdings, LLC and Bronco Midstream Holdings II, LLC	Registrant's registration statement on Form S-1, filed on November 26, 2013	File No. 333-192542	Exhibit 2.1
3.1	Certificate of Limited Partnership of CenterPoint Energy Field Services LP, as amended	Registrant's registration statement on Form S-1, filed on November 26, 2013	File No. 333-192542	Exhibit 3.1

3.2	Fifth Amended and Restated Agreement of Limited Partnership of Enable Midstream Partners, LP	Registrant's Form 8-K filed November 15, 2017	File No. 001-36413	Exhibit 3.1
4.1	Specimen Unit Certificate representing common units (included with Second Amended and Restated Agreement of Limited Partnership of Enable Midstream Partners, LP as Exhibit A thereto)	Registrant's Form 8-K filed April 22, 2014	File No. 001-36413	Exhibit 3.1
4.2	Indenture, dated as of May 27, 2014, between Enable Midstream Partners, LP and U.S. Bank National Association, as trustee	Registrant's Form 8-K filed May 29, 2014	File No. 001-36413	Exhibit 4.1
4.3	First Supplemental Indenture, dated as of May 27, 2014, by and among Enable Midstream Partners, LP, CenterPoint Energy Resources Corp., as guarantor, and U.S. Bank National Association, as trustee	Registrant's Form 8-K filed May 29, 2014	File No. 001-36413	Exhibit 4.2
4.4	Registration Rights Agreement, dated as of May 27, 2014, by and among Enable Midstream Partners, LP, CenterPoint Energy Resources Corp., as guarantor, and RBS Securities Inc., Merrill Lynch, Pierce, Fenner & Smith Incorporated, Credit Suisse Securities (USA) LLC, and RBC Capital Markets, LLC, as representatives of the initial purchasers	Registrant's Form 8-K filed May 29, 2014	File No. 001-36413	Exhibit 4.3
4.5	Registration Rights Agreement, dated as of February 18, 2016, by and between Enable Midstream Partners, LP and CenterPoint Energy, Inc.	Registrant's Form 8-K filed February 19, 2016	File No. 001-36413	Exhibit 4.1
4.6	Second Supplemental Indenture, dated as of March 9, 2017, by and among Enable Midstream Partners, LP, CenterPoint Energy Resources Corp., as guarantor, and U.S. Bank National Association, as trustee	Registrant's Form 8-K filed March 9, 2017	File No. 001-36413	Exhibit 4.2
4.7	Third Supplemental Indenture, dated as of May 10, 2018, between Enable Midstream Partners, LP and U.S. Bank National Association, as trustee	Registrant's Form 8-K filed May 10, 2018	File No. 001-36413	Exhibit 4.2
4.8	Fourth Supplemental Indenture, dated as of September 13, 2019, between Enable Midstream Partners, LP and U.S. Bank National Association, as trustee	Registrant's Form 8-K filed September 13, 2019	File No. 001-36413	Exhibit 4.2
+4.9	Description of Common Units			
10.1	Omnibus Agreement dated as of May 1, 2013 among CenterPoint Energy, Inc., OGE Energy Corp., Enogex Holdings LLC and CenterPoint Energy Field Services LP	Registrant's registration statement on Form S-1, filed on November 26, 2013	File No. 333-192542	Exhibit 10.6
10.2	Services Agreement, dated as of May 1, 2013 between CenterPoint Energy, Inc. and CenterPoint Energy Field Services LP	Registrant's registration statement on Form S-1, filed on November 26, 2013	File No. 333-192542	Exhibit 10.7
10.3	Services Agreement, dated as of May 1, 2013 between OGE Energy Corp. and CenterPoint Energy Field Services LP	Registrant's registration statement on Form S-1, filed on November 26, 2013	File No. 333-192542	Exhibit 10.8
10.4	Employee Transition Agreement, dated as of May 1, 2013 among CNP OGE GP LLC, CenterPoint Energy, Inc. and OGE Energy Corp	Registrant's registration statement on Form S-1, filed on November 26, 2013	File No. 333-192542	Exhibit 10.9
10.5	CNP Transitional Seconding Agreement, dated as of May 1, 2013 between CenterPoint Energy Field Services LP and CenterPoint Energy, Inc.	Registrant's registration statement on Form S-1, filed on November 26, 2013	File No. 333-192542	Exhibit 10.10
10.6	OGE Transitional Seconding Agreement, dated as of May 1, 2013 between CenterPoint Energy Field Services LP and OGE Energy Corp	Registrant's registration statement on Form S-1, filed on November 26, 2013	File No. 333-192542	Exhibit 10.11
10.7	Registration Rights Agreement dated as of May 1, 2013 by and among CenterPoint Energy Field Services LP, CenterPoint Energy Resources Corp., OGE Enogex Holdings LLC, and Enogex Holdings LLC	Registrant's registration statement on Form S-1, filed on November 26, 2013	File No. 333-192542	Exhibit 10.12
10.8*	OGE Energy Corp. Involuntary Severance Benefits Plans for Officers (applicable only to officers of Enogex LLC seconded to Enable Midstream Partners, LP or Enable GP, LLC or one of its subsidiaries)	Registrant's registration statement on Form S-1, filed on November 26, 2013	File No. 333-192542	Exhibit 10.13
10.9*	Enable Midstream Partners, LP Long Term Incentive Plan	Registrant's registration statement on Form S-1, filed on March 17, 2014	File No. 333-192542	Exhibit 10.18
10.10*	Enable Midstream Partners, LP Short Term Incentive Plan	Registrant's registration statement on Form S-1, filed on March 17, 2014	File No. 333-192542	Exhibit 10.19
10.11	First Amendment to Employee Transition Agreement, dated as of October 22, 2014 by and among Enable GP, LLC, CenterPoint Energy, Inc. and OGE Energy Corp	Registrant's Form 10-Q filed November 4, 2014	File No. 001-36413	Exhibit 10.1
10.12	First Amendment to OGE Transitional Seconding Agreement, dated as of October 22, 2014, between OGE Energy Corp. and Enable Midstream Partners, LP	Registrant's Form 10-Q filed November 4, 2014	File No. 001-36413	Exhibit 10.2
10.13	First Amendment to Services Agreement, dated as of October 22, 2014, between OGE Energy Corp and Enable Midstream Partners, LP	Registrant's Form 10-Q filed November 4, 2014	File No. 001-36413	Exhibit 10.3
10.14*	First Amendment to Enable Midstream Partners, LP Short Term Incentive Plan	Registrant's Form 10-K filed on February 18, 2015	File No. 001-36413	Exhibit 10.16
10.15*	Form of Annual Performance Unit Award Agreement for Senior Officers under the Enable Midstream Partners, LP Long Term Incentive Plan	Registrant's Form 8-K filed June 3, 2015	File No. 001-36413	Exhibit 10.1
10.16*	Form of Annual Restricted Unit Award Agreement for Senior Officers under the Enable Midstream Partners, LP Long Term Incentive Plan	Registrant's Form 8-K filed June 3, 2015	File No. 001-36413	Exhibit 10.2

10.17	Amended and Restated Revolving Credit Agreement dated April 6, 2018 by and among Enable Midstream Partners, LP and Citibank, N.A., as sole administrative agent, Citigroup Global Markets, Inc., Merrill Lynch, Pierce, Fenner & Smith Incorporated, RBC Capital Markets, MUFG Bank, LTD. and Wells Fargo Securities, as joint lead arrangers and joint bookrunners, Bank of America, N.A. and Wells Fargo Bank, N.A., as co-syndication agents, Royal Bank of Canada and MUFG Bank, LTD., as co-documentation agents, and the several lenders from time to time party thereto and the letter of credit issuers from time to time party thereto relating to a $1,750,000,000 five-year unsecured revolving credit facility	Registrant's Form 8-K filed April 9, 2018	File No. 001-36413	Exhibit 10.1
10.18	Term Loan Agreement, dated as of January 29, 2019, by and among Enable Midstream Partners, LP and Bank of America, N.A., as administrative agent, and the several lenders from time to time party thereto relating to a $1,000,000,000 three-year unsecured term loan facility	Registrant's Form 10-Q filed May 1, 2019	File No. 001-36413	Exhibit 10.1
10.19*	Enable Midstream Partners Deferred Compensation Plan effective January 1, 2015	Registrant's Form 10-K filed on February 17, 2016	File No. 001-36413	Exhibit 10.21
10.20*	Enable Midstream Partners Deferred Compensation Plan Adoption Agreement effective January 1, 2015	Registrant's Form 10-K filed on February 17, 2016	File No. 001-36413	Exhibit 10.22
10.21*	Second Amendment to Enable Midstream Partners, LP Short Term Incentive Plan Effective February 16, 2016	Registrant's Form 10-K filed on February 17, 2016	File No. 001-36413	Exhibit 10.23
10.22*	Enable Midstream Partners, LP Long Term Incentive Plan Annual Performance Unit Award Agreement for Senior Officers	Registrant's Form 10-K filed on February 17, 2016	File No. 001-36413	Exhibit 10.24
10.23*	Enable Midstream Partners, LP Long Term Incentive Plan Annual Phantom Unit Award Agreement for Senior Officers	Registrant's Form 10-K filed on February 17, 2016	File No. 001-36413	Exhibit 10.25
10.24*	Special Severance Agreement and General Release by and between Enable Midstream Services, LLC and Paul A. Weissgarber	Registrant's Form 10-Q filed May 4, 2016	File No. 001-36413	Exhibit 10.2
10.25	Purchase Agreement by and between Enable Midstream Partners, LP and CenterPoint Energy, Inc. dated January 28, 2016	Registrant's Form 8-K filed February 1, 2016	File No. 001-36413	Exhibit 10.1
10.26*	Enable Midstream Partners, LP Change of Control Plan	Registrant's Form 10-Q filed August 3, 2016	File No. 001-36413	Exhibit 10.1
10.27	ATM Equity Offering Sales Agreement dated as of May 12, 2017	Registrant's Form 8-K filed May 12, 2017	File No. 001-36413	Exhibit 1.1
10.28*	First Amendment to Enable Midstream Partners Deferred Compensation Plan Adoption Agreement effective January 1, 2015	Registrant's Form 10-Q filed August 1, 2017	File No. 001-36413	Exhibit 10.2
10.29*	Enable Midstream Partners, LP Long Term Incentive Plan Annual Performance Unit Award Agreement for Senior Officers	Registrant's Form 10-K filed on February 19, 2019	File No. 001-36413	Exhibit 10.29
10.30*	Enable Midstream Partners, LP Long Term Incentive Plan Annual Phantom Unit Award Agreement for Senior Officers	Registrant's Form 10-K filed on February 19, 2019	File No. 001-36413	Exhibit 10.30
+21.1	Subsidiaries of the Partnership			
+23.1	Consent of Deloitte & Touche, LLP			
+31.1	Rule 13a-14(a)/15d-14(a) Certification of principal executive officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002			
+31.2	Rule 13a-14(a)/15d-14(a) Certification of principal financial officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002			
+32.1	Section 1350 Certification of principal executive officer			
+32.2	Section 1350 Certification of principal financial officer			
+101.INS	XBRL Instance Document			
+101.SCH	XBRL Taxonomy Schema Document			
+101.PRE	XBRL Taxonomy Presentation Linkbase Document			
+101.LAB	XBRL Taxonomy Label Linkbase Document			
+101.CAL	XBRL Taxonomy Label Linkbase Document			
+101.DEF	XBRL Definition Linkbase Document			
+104	Cover Page Interactive Data File - the cover page XBRL tags are embedded within the Inline XBRL document contained in Exhibit 101			

Pursuant to Item 601(b)(4)(iii)(A) of Regulation S-K, Enable Midstream Partners, LP has not filed as exhibits to this Form 10-K certain long-term debt instruments, including indentures, under which the total amount of securities authorized does not exceed 10% of the total assets of Enable Midstream Partners, LP and its subsidiaries on a consolidated basis. Enable Midstream Partners, LP hereby agrees to furnish a copy of any such instrument to the SEC upon request.

Item 16. Form 10-K Summary

Not applicable.

SIGNATURE

Pursuant to the requirements of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

ENABLE MIDSTREAM PARTNERS, LP
(Registrant)

By: ENABLE GP, LLC
Its general partner

Date:	February 19, 2020	By:	*/s/ Tom Levescy*
			Tom Levescy
			Senior Vice President, Chief Accounting Officer and Controller
			(Principal Accounting Officer)

Pursuant to the requirements of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

Signature	**Title**	**Date**
/s/ Rodney J. Sailor Rodney J. Sailor	President and Chief Executive Officer and Director (Principal Executive Officer)	February 19, 2020
/s/ John P. Laws John P. Laws	Executive Vice President, Chief Financial Officer and Treasurer (Principal Financial Officer)	February 19, 2020
/s/ Tom Levescy Tom Levescy	Senior Vice President, Chief Accounting Officer and Controller (Principal Accounting Officer)	February 19, 2020
/s/ Scott M. Prochazka Scott M. Prochazka	Chairman of the Board	February 19, 2020
/s/ Xia Liu Xia Liu	Director	February 19, 2020
/s/ Sean Trauschke Sean Trauschke	Director	February 19, 2020
/s/ Stephen E. Merrill Stephen E. Merrill	Director	February 19, 2020
/s/ Alan N. Harris Alan N. Harris	Director	February 19, 2020
/s/ Ronnie K. Irani Ronnie K. Irani	Director	February 19, 2020
/s/ Peter H. Kind Peter H. Kind	Director	February 19, 2020

DESCRIPTION OF THE REGISTRANT'S SECURITIES REGISTERED PURSUANT TO SECTION 12 OF THE SECURITIES EXCHANGE ACT OF 1934

DESCRIPTION OF THE COMMON UNITS

The Common Units

The common units represent limited partner interests in us. The holders of common units, along with the holders of preferred units, are entitled to participate in partnership distributions and exercise the rights or privileges available to such holders under our partnership agreement. Unless the context otherwise requires, in this "Description of the Common Units," references to "unitholders" include holders of our common units only and exclude holders of our preferred units, and references to "units" include our common units only and exclude our preferred units. For a description of the relative rights and preferences of holders of common units and preferred units in and to partnership distributions, please read this section and "Cash Distribution Policy" below. References in this "Description of the Common Units" to "we," "us" and "our" mean Enable Midstream Partners, LP. For a description of voting rights, rights of distribution upon liquidation and other rights and privileges of limited partners under our partnership agreement, please read "Description of Our Partnership Agreement" below. Our outstanding common units are traded on the New York Stock Exchange under the symbol "ENBL."

Transfer of Common Units

By transfer of common units in accordance with our partnership agreement, each transferee of common units shall be admitted as a limited partner with respect to the common units transferred when such transfer and admission are reflected in our register and such limited partner becomes the record holder of the common units so transferred. Each transferee:

- will become bound and will be deemed to have agreed to be bound by the terms and conditions of our partnership agreement;
- represents that the transferee has the capacity, power and authority to enter into our partnership agreement; and
- makes the consents, acknowledgements and waivers contained in our partnership agreement

all with or without executing our partnership agreement.

We are entitled to treat the nominee holder of a common unit as the absolute owner in the event such nominee is the record holder of such common unit. In that case, the beneficial holder's rights are limited solely to those that it has against the nominee holder as a result of any agreement between the beneficial owner and the nominee holder.

Common units are securities and are transferable according to the laws governing transfers of securities. Until a common unit has been transferred on our register, we and the transfer agent may treat the record holder of the unit as the absolute owner for all purposes, except as otherwise required by law or stock exchange regulations.

DESCRIPTION OF OUR PARTNERSHIP AGREEMENT

The following is a summary of certain material provisions of our partnership agreement that relate to ownership of our common units. Our partnership agreement is included as an exhibit to the annual report on Form 10-K of which this exhibit is a part. Unless the context otherwise requires, in this "Description of our Partnership Agreement," references to "unitholders" include holders of our common units only, and exclude holders of our preferred units, and references to "units" include our common units only, and exclude our preferred units.

Capital Contributions

Unitholders are not obligated to make additional capital contributions, except as described below under "—Limited Liability."

Voting Rights

The following is a summary of the unitholder vote required for the matters specified below. Matters requiring the approval of a "unit majority" require the approval of a majority of the outstanding common units.

In voting their common units, Enable GP, LLC (our "general partner") and its affiliates will have no duty or obligation whatsoever to us or the limited partners, including any duty to act in the best interests of us or the limited partners, other than the implied covenant of good faith and fair dealing.

The incentive distribution rights may be entitled to vote in certain circumstances. Please read "—Transfer of Incentive Distribution Rights."

Issuance of additional units	No approval right by common unitholders; certain issuances require approval by 66 ⅔% of the holders of our preferred units. Please read "—Issuance of Additional Partnership Interests."
Amendment of the partnership agreement	Certain amendments may be made by our general partner without the approval of the unitholders, and certain other amendments that would or could reasonably be expected to materially adversely affect the holders of our preferred units require the approval of 66 ⅔% of such holders. Other amendments generally require the approval of a unit majority. Please read "—Amendment of the Partnership Agreement."
Merger of our partnership or the sale of all or substantially all of our assets	Unit majority and approval by 66 ⅔% of the holders of our preferred units in certain circumstances. Please read "—Merger, Consolidation, Conversion, Sale or Other Disposition of Assets."
Dissolution of our partnership	Unit majority. Please read "—Termination and Dissolution."
Continuation of our business upon dissolution	Unit majority. Please read "—Termination and Dissolution."
Withdrawal of the general partner	Under most circumstances, the approval of unitholders holding at least a majority of the outstanding common units, excluding common units held by our general partner and its affiliates, is required for the withdrawal of our general partner prior to June 30, 2024 in a manner that would cause a dissolution of our partnership. Please read "—Withdrawal or Removal of the General Partner."
Removal of the general partner	Not less than 75% of the outstanding units, voting as a single class, including units held by our general partner and its affiliates. Please read "—Withdrawal or Removal of the General Partner."
Transfer of the general partner interest	Our general partner may transfer any or all of its general partner interest in us without a vote of our unitholders but must obtain prior approval of all members of the board of directors. Please read "—Transfer of General Partner Interests."
Transfer of incentive distribution rights	Our general partner may transfer any or all of the incentive distribution rights without a vote of our unitholders. Please read "—Transfer of Incentive Distribution Rights."
Reset of incentive distribution levels	No unitholder approval required.
Transfer of ownership interests in our general partner	No unitholder approval required. Please see "—Transfer of Ownership Interests in the General Partner."

Applicable Law; Forum, Venue and Jurisdiction

Our partnership agreement is governed by Delaware law. Our partnership agreement requires that any claims, suits, actions or proceedings:

- arising out of or relating in any way to the partnership agreement (including any claims, suits or actions to interpret, apply or enforce the provisions of the partnership agreement or the duties, obligations or liabilities among limited partners or of limited partners to us, or the rights or powers of, or restrictions on, the limited partners or us);
- brought in a derivative manner on our behalf;
- asserting a claim of breach of a duty (including a fiduciary duty) owed by any director, officer, or other employee of us or our general partner, or owed by our general partner, to us or the limited partners;

- asserting a claim arising pursuant to any provision of the Delaware Revised Uniform Limited Partnership Act (the “Delaware Act”); or
- asserting a claim governed by the internal affairs doctrine

shall be exclusively brought in the Court of Chancery of the State of Delaware (or, if such court does not have subject matter jurisdiction thereof, any other court located in the State of Delaware with subject matter jurisdiction), regardless of whether such claims, suits, actions or proceedings sound in contract, tort, fraud or otherwise, are based on common law, statutory, equitable, legal or other grounds, or are derivative or direct claims. By purchasing a common unit, a limited partner is irrevocably consenting to these limitations and provisions regarding claims, suits, actions or proceedings and submitting to the exclusive jurisdiction of the Court of Chancery of the State of Delaware (or such other Delaware courts) in connection with any such claims, suits, actions or proceedings. This provision would not apply to claims brought to enforce a duty or liability created by the Securities Act of 1933, as amended (the “Securities Act”), the Securities Exchange Act of 1934, as amended (the “Exchange Act”), or any other claim for which the federal courts have exclusive jurisdiction. To the extent that any such claims may be based upon federal law claims, Section 27 of the Exchange Act creates exclusive federal jurisdiction over all suits brought to enforce any duty or liability created by the Exchange Act or the rules and regulations thereunder. Furthermore, Section 22 of the Securities Act creates concurrent jurisdiction for federal and state courts over all suits brought to enforce any duty or liability created by the Securities Act or the rules and regulations thereunder.

Limited Liability

Assuming that a limited partner does not participate in the control of our business within the meaning of the Delaware Act and that it otherwise acts in conformity with the provisions of our partnership agreement, its liability under the Delaware Act will be limited, subject to possible exceptions, to the amount of capital it is obligated to contribute to us for its common units plus its share of any undistributed profits and assets. If it were determined, however, that the right, or exercise of the right, by the limited partners as a group:

- to remove or replace our general partner;
- to approve some amendments to our partnership agreement; or
- to take other action under our partnership agreement

constituted “participation in the control” of our business for the purposes of the Delaware Act, then the limited partners could be held personally liable for our obligations under the laws of Delaware, to the same extent as our general partner. This liability would extend to persons who transact business with us who reasonably believe that the limited partner is a general partner. Neither the partnership agreement nor the Delaware Act specifically provides for legal recourse against our general partner if a limited partner were to lose limited liability through any fault of our general partner. While this does not mean that a limited partner could not seek legal recourse, we know of no precedent for this type of a claim in Delaware case law.

Under the Delaware Act, a limited partnership may not make a distribution to a partner if, after the distribution, all liabilities of the limited partnership, other than liabilities to partners on account of their limited partner interests and liabilities for which the recourse of creditors is limited to specific property of Enable Midstream Partners, LP, would exceed the fair value of the assets of the limited partnership, except that the fair value of property that is subject to a liability for which the recourse of creditors is limited is included in the assets of the limited partnership only to the extent that the fair value of that property exceeds that liability. For the purpose of determining the fair value of the assets of a limited partnership, the Delaware Act provides that the fair value of property subject to liability for which recourse of creditors is limited shall be included in the assets of the limited partnership only to the extent that the fair value of that property exceeds the non-recourse liability. The Delaware Act provides that a limited partner who receives a distribution and knew at the time of the distribution that the distribution was in violation of the Delaware Act shall be liable to the limited partnership for the amount of the distribution for three years.

Our subsidiaries conduct business in several states and we may have subsidiaries that conduct business in other states in the future. Maintenance of our limited liability as a limited partner or member of our operating subsidiaries may require compliance with legal requirements in the jurisdictions in which our operating subsidiaries conduct business, including qualifying our subsidiaries to do business there.

Limitations on the liability of limited partners or members for the obligations of a limited partnership or limited liability company have not been clearly established in many jurisdictions. If, by virtue of our limited partner interest in our operating company or otherwise, it were determined that we were conducting business in any state without compliance with the applicable limited partnership or limited liability company statute, or that the right or exercise of the right by the limited partners as a group to remove or replace our general partner, to approve some amendments to our partnership agreement, or to take other action under the partnership agreement constituted “participation in the control” of our business for purposes of the statutes of any relevant jurisdiction, then the limited partners could be held personally liable for our obligations under the law of that jurisdiction to the same extent as our general partner under the circumstances. We will operate in a manner that our general partner considers reasonable and necessary or appropriate to preserve the limited liability of the limited partners.

Issuance of Additional Partnership Interests

Our partnership agreement authorizes us to issue an unlimited number of additional partnership interests for the consideration and on the terms and conditions determined by our general partner without the approval of the unitholders.

It is possible that we will fund acquisitions through the issuance of additional common units or other partnership interests. Holders of any additional common units we issue will be entitled to share equally with the then-existing holders of common units in our distributions of available cash. In addition, the issuance of additional common units or other partnership interests may dilute the value of the interests of the then-existing holders of common units in our net assets.

In accordance with Delaware law and the provisions of our partnership agreement, we may also issue additional partnership interests that, as determined by our general partner, may have special voting rights to which the common units are not entitled. In addition, our partnership agreement does not prohibit the issuance by our subsidiaries of equity interests, which may effectively rank senior to the common units.

Each affiliate of our general partner will have the right, which it may from time to time assign in whole or in part to any of its affiliates, to purchase common units, preferred units or other partnership interests whenever, and on the same terms that, we issue those interests to persons other than our general partner and its affiliates, to the extent necessary to maintain the percentage interest of such person, including such interest represented by common units and preferred units, that existed immediately prior to each issuance. The other holders of our partnership interests will not have preemptive rights to acquire additional common units, preferred units or other partnership interests.

Amendment of the Partnership Agreement

General

Amendments to our partnership agreement may be proposed only by our general partner. However, our general partner will have no duty or obligation to propose any amendment and may decline to do so free of any duty or obligation whatsoever to us or the limited partners, including any duty to act in the best interests of us or the limited partners, other than the implied contractual covenant of good faith and fair dealing. In order to adopt a proposed amendment, other than the amendments discussed below, our general partner is required to seek written approval of the holders of the number of units required to approve the amendment or call a meeting of the limited partners to consider and vote upon the proposed amendment. Except as described below, an amendment must be approved by a unit majority.

Prohibited Amendments

No amendment may be made that would:

- enlarge the obligations of any limited partner without its consent, unless it is deemed to have occurred as a result of an amendment approved by at least a majority of the type or class of limited partner interests so affected; or
- enlarge the obligations of, restrict in any way any action by or rights of, or reduce in any way the amounts distributable, reimbursable or otherwise payable by us to our general partner or any of its affiliates without its consent, which consent may be given or withheld at its option.

The provisions of our partnership agreement preventing the amendments having the effects described in any of the clauses above can be amended upon the approval of the holders of at least 90% of the outstanding units voting together as a single class (including units owned by our general partner and its affiliates).

No Unitholder Approval

Subject to the voting rights of the preferred units, our general partner may generally make amendments to our partnership agreement without the approval of any limited partner to reflect:

- a change in our name, the location of our principal office, our registered agent or our registered office;
- the admission, substitution, withdrawal or removal of partners in accordance with our partnership agreement;
- a change that our general partner determines to be necessary or appropriate to qualify or continue our qualification as a limited partnership or a partnership in which the limited partners have limited liability under the laws of any state or to

ensure that neither we nor any of our subsidiaries will be treated as an association taxable as a corporation or otherwise taxed as an entity for U.S. federal income tax purposes;

- a change in our fiscal year or taxable year and any other changes that our general partner determines to be necessary or appropriate as a result of such change;
- an amendment that is necessary, in the opinion of our counsel, to prevent us or our general partner or its directors, officers, agents or trustees from in any manner being subjected to the provisions of the Investment Company Act of 1940, the Investment Advisors Act of 1940, or “plan asset” regulations adopted under the Employee Retirement Income Security Act of 1974, as amended, or ERISA, whether or not substantially similar to plan asset regulations currently applied or proposed by the U.S. Department of Labor;
- an amendment that our general partner determines to be necessary or appropriate for the authorization or issuance of additional partnership interests;
- any amendment expressly permitted in our partnership agreement to be made by our general partner acting alone;
- an amendment effected, necessitated or contemplated by a merger agreement that has been approved under the terms of our partnership agreement;
- any amendment that our general partner determines to be necessary or appropriate to reflect and account for the formation by us of, or our investment in, any corporation, partnership or other entity, in connection with our conduct of activities permitted by our partnership agreement;
- conversions into, mergers with or conveyances to another limited liability entity that is newly formed and has no assets, liabilities or operations at the time of the conversion, merger or conveyance other than those it receives by way of the conversion, merger or conveyance; or
- any other amendments substantially similar to any of the matters described in the clauses above.

In addition, subject to the voting rights of the preferred units, our general partner may make amendments to our partnership agreement without the approval of any limited partner if our general partner determines that those amendments:

- do not adversely affect in any material respect the limited partners considered as a whole or any particular class of partnership interests as compared to other classes of partnership interests;
- are necessary or appropriate to satisfy any requirements, conditions or guidelines contained in any opinion, directive, order, ruling or regulation of any federal or state agency or judicial authority or contained in any federal or state statute;
- are necessary or appropriate to facilitate the trading of limited partner interests (including the division of any class or classes of outstanding units into different classes to facilitate uniformity of tax consequence within such class of units) or to comply with any rule, regulation, guideline or requirement of any securities exchange on which the limited partner interests are or will be listed or admitted to trading;
- are necessary or appropriate for any action taken by our general partner relating to splits or combinations of units under the provisions of our partnership agreement; or
- are required to effect the intent expressed in the prospectus relating to our initial public offering or the intent of the provisions of our partnership agreement or are otherwise contemplated by our partnership agreement.

In addition to the above restrictions, the affirmative vote of 66 ⅔% of any series of outstanding preferred units, voting as a single class, is necessary to amend our 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 such series of preferred units.

Opinion of Counsel and Unitholder Approval

Amendments to our partnership agreement that require unitholder approval will require the approval of holders of at least 90% of the outstanding units voting as a single class unless we first obtain an opinion of counsel to the effect that an amendment will not affect the limited liability of any limited partner under Delaware law. For amendments of the type not requiring unitholder approval, our general partner will not be required to obtain such an opinion.

In addition to the above restrictions, any amendment that would have a material adverse effect on the rights or preferences of any type or class of partnership interests in relation to other classes of partnership interests will require the approval of at least a majority of the type or class of partnership interests so affected. Any amendment that would reduce the percentage of units required to take any action, other than to remove our general partner or call a meeting of unitholders, must be approved by the affirmative vote of limited partners whose aggregate outstanding units constitute not less than the percentage sought to be reduced. Any amendment that would increase the percentage of units required to remove our general partner must be approved by the affirmative vote of limited partners whose aggregate outstanding units constitute not less than 90% of outstanding units. Any amendment that would increase the percentage of units required to call a meeting of unitholders must be approved by the affirmative vote of limited partners whose aggregate outstanding units constitute at least a majority of the outstanding units.

Merger, Consolidation, Conversion, Sale or Other Disposition of Assets

A merger, consolidation or conversion of us requires the prior consent of our general partner. However, our general partner will have no duty or obligation to consent to any merger, consolidation or conversion and may decline to do so free of any duty or obligation whatsoever to us or the limited partners, including any duty to act in the best interest of us or the limited partners, other than the implied contractual covenant of good faith and fair dealing.

In addition, the partnership agreement generally prohibits our general partner without the prior approval of the holders of a unit majority, from causing us to, among other things, merge, sell, exchange or otherwise dispose of all or substantially all of our assets in a single transaction or a series of related transactions. Our general partner may, however, mortgage, pledge, hypothecate or grant a security interest in all or substantially all of our assets without that approval. Our general partner may also sell any or all of our assets under a foreclosure or other realization upon those encumbrances without that approval. Finally, our general partner may consummate any merger with another limited liability entity without the prior approval of our unitholders if we are the surviving entity in the transaction, our general partner has received an opinion of counsel regarding limited liability and tax matters, the transaction would not result in an amendment to the partnership agreement requiring unitholder approval, each of our units will be an identical unit of our partnership following the transaction, and the partnership interests to be issued by us in such merger do not exceed 20% of our outstanding partnership interests immediately prior to the transaction. In any merger, sale, exchange or other disposition of all or substantially all of our assets requiring approval of a unit majority that is not a Series A Change of Control or a Series B Change of Control (each as defined in the partnership agreement), the partnership agreement also requires approval of 66 ⅔% of the outstanding preferred units unless we agree to redeem such units.

If the conditions specified in the partnership agreement are satisfied, our general partner may convert us or any of our subsidiaries into a new limited liability entity or merge us or any of our subsidiaries into, or convey all of our assets to, a newly formed entity if the sole purpose of that conversion, merger or conveyance is to effect a mere change in our legal form into another limited liability entity, our general partner has received an opinion of counsel regarding limited liability and tax matters and the general partner determines that the governing instruments of the new entity provide the limited partners and the general partner with the same rights and obligations as contained in the partnership agreement. The unitholders are not entitled to dissenters' rights of appraisal under the partnership agreement or applicable Delaware law in the event of a conversion, merger or consolidation, a sale of all or substantially all of our assets or any other similar transaction or event.

Termination and Dissolution

We will continue as a limited partnership until dissolved and terminated under our partnership agreement. We will dissolve upon:

- the election of our general partner to dissolve us, if approved by the holders of units representing a unit majority;
- there being no limited partners, unless we are continued without dissolution in accordance with applicable Delaware law;
- the entry of a decree of judicial dissolution of our partnership; or
- the withdrawal or removal of our general partner or any other event that results in its ceasing to be our general partner other than by reason of a transfer of its general partner interest in accordance with our partnership agreement or withdrawal or removal followed by approval and admission of a successor.

Upon a dissolution under the last clause above, the holders of a unit majority may also elect, within specific time limitations, to continue our business on the same terms and conditions described in our partnership agreement by appointing as a successor general partner an entity approved by the holders of units representing a unit majority, subject to our receipt of an opinion of counsel to the effect that:

- the action would not result in the loss of limited liability of any limited partner; and
- neither our partnership nor any of our subsidiaries would be treated as an association taxable as a corporation or otherwise be taxable as an entity for U.S. federal income tax purposes upon the exercise of that right to continue (to the extent not already so treated or taxed).

Liquidation and Distribution of Proceeds

Upon our dissolution, unless we are continued as a new limited partnership, the liquidator authorized to wind up our affairs will, acting with all of the powers of our general partner that are necessary or appropriate, liquidate our assets and apply the proceeds of the liquidation as described in "Cash Distribution Policy—Distributions of Cash Upon Liquidation." The liquidator may defer liquidation or distribution of our assets for a reasonable period of time or distribute assets to partners in kind if it determines that a sale would be impractical or would cause undue loss to our partners.

Withdrawal or Removal of the General Partner

Except as described below, our general partner has agreed not to withdraw voluntarily as our general partner prior to June 30, 2024 without obtaining the approval of the holders of at least a majority of the outstanding common units, excluding common units held by the general partner and its affiliates, and furnishing an opinion of counsel regarding limited liability and tax matters. On or after June 30, 2024, our general partner may withdraw as general partner without first obtaining approval of any unitholder by giving 90 days' written notice, and that withdrawal will not constitute a violation of our partnership agreement. Notwithstanding the information above, our general partner may withdraw without unitholder approval upon 90 days' notice to the limited partners if at least 50% of the outstanding units are held or controlled by one person and its affiliates other than the general partner and its affiliates. In addition, the partnership agreement permits the general partner to sell or otherwise transfer all of its general partner interest in us without the approval of the unitholders. Please read "—Transfer of General Partner Interests" and "—Transfer of Incentive Distribution Rights."

Upon voluntary withdrawal of our general partner by giving written notice to the other partners, the holders of a unit majority may select a successor to that withdrawing general partner. If a successor is not elected, or is elected but an opinion of counsel regarding limited liability and tax matters cannot be obtained, we will be dissolved, wound up and liquidated, unless within a specified period after that withdrawal, the holders of a unit majority agree to continue our business by appointing a successor general partner. Please see "—Termination and Dissolution."

Our general partner may not be removed unless that removal is approved by the vote of the holders of not less than 75% of the outstanding units, voting together as a single class, including units held by our general partner and its affiliates, and we receive an opinion of counsel regarding limited liability and tax matters. Any removal of our general partner is also subject to the approval of a successor general partner by the vote of the holders of a majority of the outstanding common units. The ownership of more than 25% of the outstanding units by our general partner and its affiliates would give them the practical ability to prevent our general partner's removal.

Our partnership agreement also provides that if our general partner is removed as our general partner under circumstances where cause does not exist and units held by the general partner and its affiliates are not voted in favor of that removal, our general partner will have the right to convert its general partner interest and its incentive distribution rights into common units or to receive cash in exchange for those interests based on the fair market value of those interests as of the effective date of its removal.

In the event of removal of a general partner under circumstances where cause exists or withdrawal of a general partner where that withdrawal violates our partnership agreement, a successor general partner will have the option to purchase the general partner interest and incentive distribution rights of the departing general partner for a cash payment equal to the fair market value of those interests. Under all other circumstances where a general partner withdraws or is removed by the limited partners, the departing general partner will have the option to require the successor general partner to purchase the general partner interest of the departing general partner and its incentive distribution rights for fair market value. In each case, this fair market value will be determined by agreement between the departing general partner and the successor general partner. If no agreement is reached, an independent investment banking firm or other independent expert selected by the departing general partner and the successor general partner will determine the fair market value. Or, if the departing general partner and the successor general partner cannot agree upon an expert, then an expert chosen by agreement of the experts selected by each of them will determine the fair market value.

If the option described above is not exercised by either the departing general partner or the successor general partner, the departing general partner will become a limited partner and its general partner interest and its incentive distribution rights will automatically convert into common units pursuant to a valuation of those interests as determined by an investment banking firm or other independent expert selected in the manner described in the preceding paragraph.

In addition, we will be required to reimburse the departing general partner for all amounts due the departing general partner, including, without limitation, all employee-related liabilities, including severance liabilities, incurred for the termination of any employees employed by the departing general partner or its affiliates for our benefit.

Transfer of General Partner Interests

Our general partner may transfer all or any of its general partner interest without the approval of our unitholders, but any such transfer requires the approval of all members of the board of directors. As a condition of this transfer, the transferee must assume, among other things, the rights and duties of our general partner, agree to be bound by the provisions of our partnership agreement, and furnish an opinion of counsel regarding limited liability and tax matters.

Transfer of Ownership Interests in the General Partner

OGE Energy Corp., an Oklahoma corporation ("OGE Energy"), or CenterPoint Energy, Inc., a Texas corporation ("CenterPoint Energy"), and their subsidiaries may sell or transfer their membership interest in our general partner to an affiliate or third party without the approval of our unitholders; provided that each of OGE Energy and CenterPoint Energy have rights of first offer and rights of first refusal with respect to proposed sales by the other party of such party's membership interest to a third party.

Transfer of Common Units by Sponsors

Each of OGE Energy and CenterPoint Energy has a right of first offer and a right of first refusal with respect to proposed sales by the other party of 5% or more of such party's common units.

Transfer of Incentive Distribution Rights

At any time, our general partner may transfer its incentive distribution rights to an affiliate or third party without the approval of our unitholders. If less than a majority of the incentive distribution rights are held by our general partner or its affiliates, the holders of incentive distribution rights will be entitled to vote on all matters submitted to a vote of unitholders, other than amendments to the partnership agreement and other matters that our general partner determines do not adversely affect the holders of the incentive distribution rights in any material respect. On any matter in which the holders of incentive distribution rights are entitled to vote, such holders will vote together with the common units, and such incentive distribution rights shall be treated in all respects as common units when sending notices of a meeting of our limited partners to vote on any matter (unless otherwise required by law), calculating required votes, determining the presence of a quorum or for other similar purposes under our partnership agreement. The relative voting power of the holders of the incentive distribution rights and the common units will be set in the same proportion as cumulative cash distributions, if any, in respect of the incentive distribution rights for the four consecutive quarters prior to the record date for the vote bears to the cumulative cash distributions in respect of such class of units for such four quarters.

Change of Management Provisions

Our partnership agreement contains specific provisions that are intended to discourage a person or group from attempting to remove our general partner as our general partner or otherwise change our management. If any person or group other than our general partner and its affiliates acquires beneficial ownership of 20% or more of any class of units, that person or group loses voting rights on all of its units. This loss of voting rights does not apply to any person or group that acquires the units from our general partner or its affiliates and any transferees of that person or group who are notified by our general partner that they will not lose their voting rights to any person or group who acquires the units with the prior approval of the board of directors of our general partner or to any person or group with respect to the preferred units.

Our partnership agreement also provides that if our general partner is removed as our general partner under circumstances where cause does not exist and units held by our general partner and its affiliates are not voted in favor of that removal, our general partner will have the right to convert its general partner units and its incentive distribution rights into common units or to receive cash in exchange for those interests based on the fair market value of those interests as of the effective date of its removal.

Limited Call Right

If at any time our general partner and its affiliates own more than 90% of the then-issued and outstanding limited partner interests of any class, our general partner will have the right, which it may assign in whole or in part to any of its affiliates or to us, to acquire all, but not less than all, of the limited partner interests of such class held by unaffiliated persons as of a record date to be selected by our general partner, on at least 10 but not more than 60 days' notice. If our general partner and its affiliates reduce their ownership percentage to below 70% of the outstanding limited partner interests of any class, the ownership threshold to exercise the call right will be permanently reduced to 80%. The purchase price in the event of this purchase is the greater of:

- the highest cash price paid by either of our general partner or any of its affiliates for any limited partner interests of the class purchased within the 90 days preceding the date on which our general partner first mails notice of its election to purchase those limited partner interests; and
- the current market price calculated in accordance with our partnership agreement as of the date three business days before the date the notice is mailed.

As a result of our general partner's right to purchase outstanding limited partner interests, a holder of limited partner interests may have his limited partner interests purchased at a price that may be lower than market prices at various times prior to such purchase or lower than a unitholder may anticipate the market price to be in the future. The tax consequences to a unitholder of the exercise of this call right are the same as a sale by that unitholder of his common units in the market.

Notwithstanding the foregoing, the limited call right described above does not apply to the preferred units.

Meetings; Voting

Except as described below regarding a person or group owning 20% or more of any class of units then outstanding, record holders of units on the record date will be entitled to notice of, and to vote at, meetings of our limited partners and to act upon matters for which approvals may be solicited.

Our general partner does not anticipate that any meeting of unitholders will be called in the foreseeable future. Any action that is required or permitted to be taken by the unitholders may be taken either at a meeting of the unitholders or, if authorized by our general partner, without a meeting if consents in writing describing the action so taken are signed by holders of the number of units that would be necessary to authorize or take that action at a meeting where all limited partners were present and voted. Meetings of the unitholders may be called by our general partner or by unitholders owning at least 20% of the outstanding units of the class for which a meeting is proposed. Unitholders may vote either in person or by proxy at meetings. The holders of a majority of the outstanding units of the class or classes for which a meeting has been called represented in person or by proxy will constitute a quorum unless any action by the unitholders requires approval by holders of a greater percentage of the units, in which case the quorum will be the greater percentage.

Each record holder of a unit has a vote according to its percentage interest in us; however, the holders of our preferred units have special voting rights, and additional limited partner interests having special voting rights could be issued. Please read "—Issuance of Additional Partnership Interests."

If at any time any person or group, other than our general partner and its affiliates, a direct transferee of our general partner and its affiliates, a transferee of such direct transferee who is notified by our general partner that it will not lose its voting rights, or any person or group with respect to the preferred units acquires, in the aggregate, beneficial ownership of 20% or more of any class of units then outstanding, that person or group will lose voting rights on all of its units and the units may not be voted on any matter and will not be considered to be outstanding when sending notices of a meeting of unitholders, calculating required votes, determining the presence of a quorum or for other similar purposes. Common units held in nominee or street name account will be voted by the broker or other nominee in accordance with the instruction of the beneficial owner unless the arrangement between the beneficial owner and its nominee provides otherwise.

Any notice, demand, request, report or proxy material required or permitted to be given or made to record holders of common units under our partnership agreement will be delivered to the record holder by us or by the transfer agent.

Status as Limited Partner

By transfer of common units in accordance with our partnership agreement, each transferee of common units shall be admitted as a limited partner with respect to the common units transferred when such transfer and admission is reflected in our register. Except as described under "—Limited Liability," the common units will be fully paid, and unitholders will not be required to make additional contributions.

Ineligible Holders; Redemption

Under our partnership agreement, an "Eligible Holder" is a limited partner whose (a) U.S. 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 the Federal Energy Regulatory Commission (FERC) or an analogous regulatory body and (b) 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 at any time our general partner determines, with the advice of counsel, that one or more limited partners are not Eligible Holders (any such limited partner, an Ineligible Holder), then our general partner may request any limited partner to furnish to the general partner an executed certification or other information about his U.S. federal income tax status and/or nationality, citizenship or related status. If a limited partner fails to furnish such certification or other requested information within 30 days (or such other period as the general partner may determine) after a request for such certification or other information, or our general partner determines after receipt of the information that the limited partner is not an Eligible Holder, the limited partner may be treated as an Ineligible Holder. An Ineligible Holder does not have the right to direct the voting of his units and may not receive distributions in kind upon our liquidation.

Furthermore, we have the right to redeem all of the common units of any holder that our general partner concludes is an Ineligible Holder or fails to furnish the information requested by our general partner. The redemption price in the event of such redemption for each unit held by such unitholder will be the current market price of such unit (the date of determination of which shall be the date fixed for redemption). The redemption price will be paid, as determined by our general partner, in cash or by delivery of a promissory note. Any such promissory note will bear interest at the rate of 5.0% annually and be payable in three equal annual installments of principal and accrued interest, commencing one year after the redemption date.

Books and Reports

Our general partner is required to keep appropriate books of our business at our principal offices. The books will be maintained for financial reporting purposes on an accrual basis. For tax and fiscal reporting purposes, our fiscal year is the calendar year.

We will mail or make available to record holders of partnership interests, within 105 days after the close of each fiscal year, an annual report containing audited financial statements and a report on those financial statements by our independent public accountants. Except for our fourth quarter, we will also mail or make available summary financial information within 50 days after the close of each quarter.

We will furnish each record holder of a unit with information reasonably required for tax reporting purposes within 90 days after the close of each calendar year. This information is expected to be furnished in summary form so that some complex calculations normally required of partners can be avoided. Our ability to furnish this summary information to unitholders will depend on the cooperation of unitholders in supplying us with specific information. Every unitholder will receive information to assist him in determining his federal and state tax liability and filing his federal and state income tax returns, regardless of whether he supplies us with information.

Right to Inspect Our Books and Records

Our partnership agreement provides that a limited partner can, for a purpose reasonably related to his interest as a limited partner, upon reasonable written demand stating the purpose of such demand and at his own expense, have furnished to him:

- a current list of the name and last known address of each record holder;
- copies of our partnership agreement and our certificate of limited partnership and all amendments thereto; and
- certain information regarding the status of our business and financial condition.

Our general partner may, and intends to, keep confidential from the limited partners trade secrets or other information the disclosure of which our general partner in good faith believes is not in our best interests or that we are required by law or by agreements with third parties to keep confidential. Our partnership agreement limits the right to information that a limited partner would otherwise have under Delaware law.

CASH DISTRIBUTION POLICY

References in this “Cash Distribution Policy” to “we,” “us” and “our” mean Enable Midstream Partners, LP. Unless the context otherwise requires, in this “Cash Distribution Policy” references to “unitholders” include holders of our common units only, and exclude holders of our preferred units, and references to “units” include our common units only, and exclude our preferred units.

Distributions of Available Cash

General

Subject to the payment of distributions on the preferred units, our partnership agreement requires that, within 60 days after the end of each quarter, we distribute all of our available cash to unitholders of record on the applicable record date.

Definition of Available Cash

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 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.

The purpose and effect of the last bullet point above is to allow our general partner, if it so decides, to use cash from working capital borrowings made after the end of the quarter, but on or before the date of determination of available cash for that quarter, to pay distributions to unitholders. Under our partnership agreement, working capital borrowings are generally borrowings that are made under a credit facility, commercial paper facility or similar financing arrangement, and in all cases are used solely for working capital purposes or to pay distributions to partners, and with the intent of the borrower to repay such borrowings within 12 months with funds other than from additional working capital borrowings.

Intent to Distribute the Minimum Quarterly Distribution

We intend to make a minimum quarterly distribution to the holders of our common units of at least $0.2875 per unit, 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. 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 our policy and the decision to make any distribution is determined by our general partner, in accordance with the terms of our partnership agreement.

General Partner Interest and Incentive Distribution Rights

Our general partner owns a non-economic general partner interest in us and thus will not be entitled to distributions that we make prior to our liquidation in respect of such general partner interest. Our general partner currently holds incentive distribution rights that entitle it to receive increasing percentages, up to a maximum of 50.0%, of the cash we distribute from operating surplus (as defined below) in excess of $0.330625 per unit per quarter. The maximum distribution of 50.0% does not include any distributions that our general partner or its affiliates may receive on common units that they own. Please read "—Incentive Distribution Rights" for additional information.

Operating Surplus and Capital Surplus

General

All cash distributed to unitholders will be characterized as either being paid from "operating surplus" or "capital surplus." We treat distributions of available cash from operating surplus differently than distributions of available cash from capital surplus.

Operating Surplus

We define operating surplus as:

- $300 million; *plus*
- all of our cash receipts after the closing of our initial public offering, excluding cash from interim capital transactions (as defined below) and the termination of hedge contracts, provided that cash receipts from the termination of a commodity hedge or interest rate hedge prior to its specified termination date shall be included in operating surplus in equal quarterly installments over the remaining scheduled life of such commodity hedge or interest rate hedge; *plus*
- working capital borrowings made after the end of a quarter but on or before the date of determination of operating surplus for that quarter; *plus*
- cash distributions (including incremental distributions on incentive distribution rights) paid in respect of equity issued, other than equity issued in our initial public offering, to finance all or a portion of expansion capital expenditures in respect of the period from the date that we enter into a binding obligation to commence the construction, development, replacement, improvement or expansion of a capital asset and ending on the earlier to occur of the date the capital asset commences commercial service and the date that it is abandoned or disposed of; *plus*
- cash distributions (including incremental distributions on incentive distribution rights) paid in respect of equity issued, other than equity issued in our initial public offering, to pay interest and related fees on debt incurred, or to pay distributions on equity issued, to finance the expansion capital expenditures referred to in the prior bullet; *less*
- all of our operating expenditures (as defined below) after April 16, 2014, the closing of our initial public offering; *less*
- the amount of cash reserves established by our general partner to provide funds for future operating expenditures; *less*
- all working capital borrowings not repaid within 12 months after having been incurred or repaid within such twelve-month period with the proceeds of additional working capital borrowings; *less*
- any cash loss realized on disposition of an investment capital expenditure.

As described above, operating surplus does not reflect actual cash on hand that is available for distribution to our unitholders and is not limited to cash generated by our operations. For example, it includes a provision that will enable us, if we choose, to distribute as operating surplus up to $300 million of cash we receive in the future from non-operating sources such as asset sales, issuances of securities and long-term borrowings that would otherwise be distributed as capital surplus. In addition, the effect of including, as described above, certain cash distributions on equity interests in operating surplus will be to increase operating surplus by the amount of any such cash distributions. As a result, we may also distribute as operating surplus up to the amount of any such cash that we receive from non-operating sources.

The proceeds of working capital borrowings increase operating surplus and repayments of working capital borrowings are generally operating expenditures (as described below) and thus reduce operating surplus when repayments are made. However, if working capital borrowings, which increase operating surplus, are not repaid during the 12-month period following the borrowing, they will be deemed repaid at the end of such period, thus decreasing operating surplus at such time. When such working capital borrowings are in fact repaid, they will not be treated as a further reduction in operating surplus because operating surplus will have been previously reduced by the deemed repayment.

We define interim capital transactions as (i) borrowings, refinancings or refundings of indebtedness (other than working capital borrowings and items purchased on open account or for a deferred purchase price in the ordinary course of business) and sales of debt securities, (ii) issuances of equity securities, (iii) sales or other dispositions of assets, other than sales or other dispositions of inventory, accounts receivable and other assets in the ordinary course of business and sales or other dispositions of assets as part of normal asset retirements or replacements and (iv) capital contributions received by a group member.

We define operating expenditures as all of our cash expenditures, including, but not limited to, taxes, reimbursements of expenses of our general partner and its affiliates, director, officer and employee compensation, debt service payments, payments made in the ordinary course of business under interest rate hedge contracts and commodity hedge contracts (provided that payments made in connection with the termination of any interest rate hedge contract or commodity hedge contract prior to the expiration of its settlement or termination date specified therein will be included in operating expenditures in equal quarterly installments over the remaining scheduled life of such interest rate hedge contract or commodity hedge contract and amounts paid in connection with the initial purchase of a rate hedge contract or a commodity hedge contract will be amortized at the life of such rate hedge contract or commodity hedge contract), maintenance capital expenditures (as discussed in further detail below) and repayment of working capital borrowings; provided, however, that operating expenditures will not include:

- repayments of working capital borrowings where such borrowings have previously been deemed to have been repaid (as described above);

- payments (including prepayments and prepayment penalties) of principal of and premium on indebtedness other than working capital borrowings;
- expansion capital expenditures;
- investment capital expenditures;
- payment of transaction expenses (including taxes) relating to interim capital transactions;
- distributions to our partners;
- repurchases of partnership interests (excluding repurchases we make to satisfy obligations under employee benefit plans); or
- any expenditures made to fund certain demand fees using a portion of the proceeds of our initial public offering.

Capital Surplus

Capital surplus is defined in our partnership agreement as any distribution of available cash in excess of our cumulative operating surplus. Accordingly, except as described above, capital surplus would generally be generated by:

- borrowings other than working capital borrowings;
- sales of our equity and debt securities;
- sales or other dispositions of assets, other than inventory, accounts receivable and other assets sold in the ordinary course of business or as part of ordinary course retirement or replacement of assets; and
- capital contributions received.

Characterization of Cash Distributions

Our partnership agreement requires that we treat all available cash distributed as coming from operating surplus until the sum of all available cash distributed since the closing of our initial public offering equals the operating surplus from the closing of our initial public offering through the end of the quarter immediately preceding that distribution. Our partnership agreement requires that we treat any amount distributed in excess of operating surplus, regardless of its source, as capital surplus. Our partnership agreement treats a distribution of capital surplus as the repayment of the initial unit price from our initial public offering and as a return of capital. We do not anticipate that we will make any distributions from capital surplus.

Capital Expenditures

Expansion capital expenditures are cash expenditures incurred for acquisitions or capital improvements that we expect will increase our asset base, operating income or operating capacity over the long term. Examples of expansion capital expenditures include the acquisition of equipment and the construction, development or acquisition of additional pipeline, storage, gathering or processing capacity, including well connections, to the extent such capital expenditures are expected to expand our asset base, operating capacity or our operating income. Expansion capital expenditures include interest payments (and related fees) on debt incurred to finance all or a portion of expansion capital expenditures in respect of the period from the date that we enter into a binding obligation to commence the construction, development, replacement, improvement or expansion of a capital asset and ending on the earlier to occur of the date that such capital improvement commences commercial service and the date that such capital improvement is abandoned or disposed of.

Maintenance capital expenditures 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 asset base, operating capacity or operating income. Examples of maintenance capital expenditures are expenditures to repair, refurbish and replace pipelines, to maintain equipment reliability, integrity and safety and to address environmental laws and regulations. Maintenance capital expenditures are included in operating expenditures and thus will reduce operating surplus.

Investment capital expenditures are those capital expenditures that are neither maintenance capital expenditures nor expansion capital expenditures. Investment capital expenditures largely will consist of capital expenditures made for investment purposes. Examples of investment capital expenditures include traditional capital expenditures for investment purposes, such as purchases of securities, as well as other capital expenditures that might be made in lieu of such traditional investment capital expenditures, such as the acquisition of a capital asset for investment purposes or development of facilities that are in excess of the maintenance of our existing operating capacity or operating income, but that are not expected to expand our asset base, operating capacity or operating income over the long term.

Capital expenditures that are made in part for maintenance capital purposes, investment capital purposes and/or expansion capital purposes will be allocated as maintenance capital expenditures, investment capital expenditures or expansion capital expenditure by our general partner.

Distributions of Available Cash from Operating Surplus

Subject to the payment of distributions on the preferred units, we will make distributions of available cash from operating surplus to our common unitholders for any quarter in the following manner:

- *first*, to all unitholders, pro rata, until we distribute for each outstanding unit an amount equal to the minimum quarterly distribution for that quarter; and
- *thereafter*, in the manner described in "—Incentive Distribution Rights" below.

The preceding discussion is based on the assumption that we do not issue additional classes of equity securities.

Incentive Distribution Rights

Incentive distribution rights represent the right to receive an increasing percentage (15.0%, 25.0% and 50.0%) of quarterly distributions of available cash from operating surplus after the minimum quarterly distribution and the target distribution levels have been achieved. Our general partner currently holds the incentive distribution rights, but may transfer these rights separately from its general partner interest, subject to restrictions in our partnership agreement.

The following discussion assumes that our general partner continues to own the incentive distribution rights.

If for any quarter:

- we have distributed available cash from operating surplus to the holders of our preferred units to the extent of the distribution preference on the preferred units; and
- we have distributed available cash from operating surplus to the common unitholders in an amount equal to the minimum quarterly distribution.

then, we will distribute any additional available cash from operating surplus for that quarter among the unitholders and our general partner in the following manner:

- *first*, to all unitholders, pro rata, until each unitholder receives a total of $0.330625 per unit for that quarter (the first target distribution);
- *second*, 85.0% to all unitholders, pro rata, and 15.0% to our general partner, until each unitholder receives a total of $0.359375 per unit for that quarter (the second target distribution);
- *third*, 75.0% to all unitholders, pro rata, and 25.0% to our general partner, until each unitholder receives a total of $0.431250 per unit for that quarter (the third target distribution); and
- thereafter, 50.0% to all unitholders, pro rata, and 50.0% to our general partner.

Percentage Allocations of Available Cash from Operating Surplus

The following table illustrates the percentage allocations of available cash from operating surplus (after payment of the distribution preference on the preferred units) between the common 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 common 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.

	Total Quarterly Distribution Per Unit Target Amount	Marginal Percentage Interest in Distributions	
		Common Unitholders	General Partner
Minimum Quarterly Distribution	$0.287500	100.0%	0.0%
First Target Distribution	up to $0.330625	100.0%	0.0%
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%

General Partner's Right to Reset Incentive Distribution Levels

Our general partner, as the initial holder of our incentive distribution rights, has the right under our partnership agreement, subject to certain conditions, to elect to relinquish the right to receive incentive distribution payments based on the initial target distribution levels and to reset, at higher levels, the minimum quarterly distribution amount and target distribution levels upon which the incentive distribution payments to our general partner would be set. If our general partner transfers all or a portion of our incentive distribution rights in the future, then the holder or holders of a majority of our incentive distribution rights will be entitled to exercise this right. The following discussion assumes that our general partner holds all of the incentive distribution rights at the time that a reset election is made. Our general partner's right to reset the minimum quarterly distribution amount and the target distribution levels upon which the incentive distributions payable to our general partner are based may be exercised, without approval of our unitholders or the conflicts committee, at any time if we have made cash distributions to the holders of the incentive distribution rights at the highest level of incentive distribution for each of the four consecutive fiscal quarters immediately preceding such time and the amount of each such distribution did not exceed adjusted operating surplus for such quarter, respectively. If our general partner and its affiliates are not the holders of a majority of the incentive distribution rights at the time an election is made to reset the minimum quarterly distribution amount and the target distribution levels, then the proposed reset will be subject to the prior written concurrence of the general partner that the conditions described above have been satisfied. The reset minimum quarterly distribution amount and target distribution levels will be higher than the minimum quarterly distribution amount and the target distribution levels prior to the reset such that our general partner will not receive any incentive distributions under the reset target distribution levels until cash distributions per unit following this event increase as described below. We anticipate that our general partner would exercise this reset right in order to facilitate acquisitions or internal growth projects that would otherwise not be sufficiently accretive to cash distributions per common unit, taking into account the existing levels of incentive distribution payments being made to our general partner.

In connection with the resetting of the minimum quarterly distribution amount and the target distribution levels and the corresponding relinquishment by our general partner of incentive distribution payments based on the target distributions prior to the reset, our general partner will be entitled to receive a number of newly issued common units based on a predetermined formula described below that takes into account the "cash parity" value of the average cash distributions related to the incentive distribution rights received by our general partner for the two quarters immediately preceding the reset event as compared to the average cash distributions per common unit during that two-quarter period.

The number of common units that our general partner would be entitled to receive from us in connection with a resetting of the minimum quarterly distribution amount and the target distribution levels then in effect would be equal to the quotient determined by dividing (x) the average amount of cash distributions received by our general partner in respect of its incentive distribution rights during the two consecutive fiscal quarters ended immediately prior to the date of such reset election by (y) the average of the amount of cash distributed per common unit during each of these two quarters.

Following a reset election, 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 (which amount we refer to as the reset minimum quarterly distribution) and the target distribution levels will be reset to be correspondingly higher such that we would distribute all of our available cash from operating surplus (after payment of the distribution preference on the preferred units) for each quarter thereafter as follows:

- *first*, to all unitholders, pro rata, until each unitholder receives an amount equal to 115.0% of the reset minimum quarterly distribution for that quarter;

- *second*, 85.0% to all unitholders, pro rata, and 15.0% to our general partner, until each unitholder receives an amount per unit equal to 125.0% of the reset minimum quarterly distribution for the quarter;
- *third*, 75.0% to all unitholders, pro rata, and 25.0% to our general partner, until each unitholder receives an amount per unit equal to 150.0% of the reset minimum quarterly distribution for the quarter; and
- *thereafter*, 50.0% to all unitholders, pro rata, and 50.0% to our general partner.

Our general partner will be entitled to cause the minimum quarterly distribution amount and the target distribution levels to be reset on more than one occasion, provided that it may not make a reset election except at a time when it has received incentive distributions for the immediately preceding four consecutive fiscal quarters based on the highest level of incentive distributions that it is entitled to receive under our partnership agreement.

Distributions from Capital Surplus

How Distributions from Capital Surplus Will Be Made

Subject to the payment of distributions on the preferred units, we will make distributions of available cash from capital surplus, if any, in the following manner:

- *first*, to all unitholders, pro rata, until the minimum quarterly distribution is reduced to zero, as described below under "—Effect of a Distribution from Capital Surplus"; and
- *thereafter*, as if such distributions were from operating surplus.

The preceding discussion is based on the assumption that we do not issue additional classes of equity securities.

Effect of a Distribution from Capital Surplus

Our partnership agreement treats a distribution of capital surplus as the repayment of the initial unit price from our initial public offering, which is a return of capital. The initial public offering price less any distributions of capital surplus per unit is referred to as the "unrecovered initial unit price." Each time a distribution of capital surplus is made, the minimum quarterly distribution and the target distribution levels will be reduced in the same proportion as the corresponding reduction in the unrecovered initial unit price. Because distributions of capital surplus will reduce the minimum quarterly distribution after any of these distributions are made, it may be easier for our general partner to receive incentive distributions. However, any distribution of capital surplus before the unrecovered initial unit price is reduced to zero cannot be applied to the payment of the minimum quarterly distribution.

Once we distribute capital surplus on a unit issued in our initial public offering in an amount equal to the initial unit price, we will reduce the minimum quarterly distribution and the target distribution levels to zero. Then, we will make all future distributions from operating surplus, with 50.0% being paid to the unitholders, pro rata, and 50.0% to the holder of our incentive distribution rights.

Adjustment to the Minimum Quarterly Distribution and Target Distribution Levels

In addition to adjusting the minimum quarterly distribution and target distribution levels to reflect a distribution of capital surplus, if we combine our units into fewer units or subdivide our units into a greater number of units, we will proportionately adjust:

- the minimum quarterly distribution;
- target distribution levels; and
- the unrecovered initial unit price.

For example, if a two-for-one split of the common units should occur, the minimum quarterly distribution, the target distribution levels and the unrecovered initial unit price would each be reduced to 50.0% of its initial level. We will not make any adjustment by reason of the issuance of additional units for cash or property (including the issuance of additional units under any compensation or benefit plans).

In addition, if legislation is enacted or if the official interpretation of existing law is modified by a governmental authority, so that we become taxable as a corporation or otherwise subject to taxation as an entity for federal, state or local income tax purposes, our partnership agreement specifies that the minimum quarterly distribution and the target distribution levels for each quarter shall be reduced by multiplying each distribution level by a fraction, the numerator of which is available cash for that quarter (reduced by the amount of the estimated tax liability for such quarter payable by reason of such legislation or interpretation) and the denominator of which is the sum of available cash for that quarter (reduced by the amount of the estimated tax liability for such quarter payable by reason of such legislation or interpretation) plus our general partner's estimate of our aggregate liability for the quarter for such income taxes payable by reason of such legislation or interpretation. To the extent that the actual tax liability differs from the estimated tax liability for any quarter, the difference may be accounted for in subsequent quarters.

Distributions of Cash Upon Liquidation

General

If we dissolve in accordance with our partnership agreement, we will sell or otherwise dispose of our assets in a process called liquidation. We will first apply the proceeds of liquidation to the payment of our creditors. We will distribute any remaining proceeds to the unitholders and our general partner, in accordance with their capital account balances, as adjusted to reflect any gain or loss upon the sale or other disposition of our assets in liquidation; provided, however, that in preference to the holders of our other securities, we will distribute to the holders of preferred units an amount equal to any unpaid distributions on such preferred units and the positive value in the capital account of each such preferred unit holder in respect of such preferred units.

Manner of Adjustments for Gain

The manner of the adjustment for gain is set forth in our partnership agreement. We will allocate any gain to our partners in the following manner:

- *first*, to our general partner to the extent of any negative balance in its capital account;
- *second*, to the preferred unitholders, until the capital account balance of such holders equals the stated liquidation preference with respect to such holders' preferred units;
- *third*, to the common unitholders, pro rata, until the capital account for each common unit is equal to the sum of: (1) the unrecovered initial unit price; and (2) the amount of the minimum quarterly distribution for the quarter during which our liquidation occurs;
- *fourth*, to all common unitholders, pro rata, until we allocate under this paragraph an amount per unit equal to: (1) the sum of the excess of the first target distribution per unit over the minimum quarterly distribution per unit for each quarter of our existence; less (2) the cumulative amount per unit of any distributions of available cash from operating surplus in excess of the minimum quarterly distribution per unit that we distributed to the common unitholders, pro rata, for each quarter of our existence;
- *fifth*, 85.0% to all common unitholders, pro rata, and 15.0% to our general partner, until we allocate under this paragraph an amount per unit equal to: (1) the sum of the excess of the second target distribution per unit over the first target distribution per unit for each quarter of our existence; less (2) the cumulative amount per unit of any distributions of available cash from operating surplus in excess of the first target distribution per unit that we distributed 85.0% to the common unitholders, pro rata, and 15.0% to our general partner for each quarter of our existence;
- *sixth*, 75.0% to all common unitholders, pro rata, and 25.0% to our general partner, until we allocate under this paragraph an amount per unit equal to: (1) the sum of the excess of the third target distribution per unit over the second target distribution per unit for each quarter of our existence; less (2) the cumulative amount per unit of any distributions of available cash from operating surplus in excess of the second target distribution per unit that we distributed 75.0% to the common unitholders, pro rata, and 25.0% to our general partner for each quarter of our existence; and
- *thereafter*, 50.0% to all common unitholders, pro rata, and 50.0% to our general partner.

The percentages set forth above are based on the assumption that our general partner has not transferred its incentive distribution rights and that we do not issue additional classes of equity securities.

If certain losses were allocated to holders of our preferred units in a taxable period preceding liquidation, such holders will be allocated gain upon liquidation to the extent the stated liquidation preference exceeds the capital account balance of such holders with respect to the preferred units.

Manner of Adjustments for Losses

After making allocations of loss to the general partner and the unitholders in a manner intended to offset in reverse order the allocations of gains that have previously been allocated, we will generally allocate any loss to our general partner and unitholders in the following manner:

- *first*, to the holders of common units in proportion to the positive balances in their capital accounts until the capital accounts of the common unitholders have been reduced to zero;
- *second*, to the holders of preferred units in proportion to the positive balances in their capital accounts until the capital accounts of the holders of the preferred units have been reduced to zero; and
- *thereafter*, 100.0% to our general partner.

Adjustments to Capital Accounts

Our partnership agreement requires that we make adjustments to capital accounts upon the issuance of additional units (including as a result of the conversion of our preferred units into common units). In this regard, our partnership agreement specifies that we allocate any unrealized and, for tax purposes, unrecognized gain resulting from the adjustments to the unitholders (including holders of our outstanding preferred units) and the general partner in the same manner as we allocate gain upon liquidation. In the event that we make positive adjustments to the capital accounts upon the issuance of additional units, our partnership agreement requires that we generally allocate any later negative adjustments to the capital accounts resulting from the issuance of additional units or upon our liquidation in a manner which results, to the extent possible, in the partners' capital account balances equaling the amount which they would have been if no earlier positive adjustments to the capital accounts had been made. In contrast to the allocations of gain, and except as provided above, we generally will allocate any unrealized and unrecognized loss resulting from the adjustments to capital accounts upon the issuance of additional units to the unitholders and our general partner based on their respective percentage ownership of us. If we make negative adjustments to the capital accounts as a result of such loss, future positive adjustments resulting from the issuance of additional units will be allocated in a manner designed to reverse the prior negative adjustments, and special allocations will be made upon liquidation in a manner that results, to the extent possible, in our unitholders' capital account balances equaling the amounts they would have been if no earlier adjustments for loss had been made.

Exhibit 21.1

Subsidiaries of Enable Midstream Partners, LP

Subsidiary	State of Incorporation
Enable Gas Gathering, LLC	Oklahoma
Enable Gas Transmission, LLC	Delaware
Enable Gathering & Processing, LLC	Oklahoma
Enable Oklahoma Intrastate Transmission, LLC	Delaware
Enable Products, LLC	Oklahoma

Exhibit 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement No. 333-215670 on Amendment No. 1 to Form S-3, Registration Statement No. 333-212192 on Form S-3D, Registration Statement No. 333-195226 on Form S-8 and Registration Statement No. 333-224698 on Form S-3ASR of our reports dated February 19, 2020 relating to the consolidated financial statements of Enable Midstream Partners, LP and subsidiaries, (collectively the “Partnership”), and the effectiveness of the Partnership’s internal control over financial reporting, appearing in this Annual Report on Form 10-K of the Partnership for the year ended December 31, 2019.

/s/ DELOITTE & TOUCHE LLP

Oklahoma City, Oklahoma
February 19, 2020

Exhibit 31.1

CERTIFICATIONS

I, Rodney J. Sailor, certify that:

1. I have reviewed this annual report on Form 10-K of Enable Midstream Partners, LP;

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

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

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

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

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

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

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

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

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

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

Date: February 19, 2020

/s/ Rodney J. Sailor

Rodney J. Sailor

President and Chief Executive Officer, Enable GP, LLC, the General Partner of Enable Midstream Partners, LP

(Principal Executive Officer)

Exhibit 31.2

CERTIFICATIONS

I, John P. Laws, certify that:

1. I have reviewed this annual report on Form 10-K of Enable Midstream Partners, LP;

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

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

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

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

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

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

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

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

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

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

Date: February 19, 2020

/s/ John P. Laws

John P. Laws

Executive Vice President, Chief Financial Officer and Treasurer, Enable GP, LLC, the General Partner of Enable Midstream Partners, LP

(Principal Financial Officer)

Exhibit 32.1

**CERTIFICATION PURSUANT TO 18 U.S.C. SECTION 1350
AS ADOPTED PURSUANT TO SECTION 906
OF THE SARBANES-OXLEY ACT OF 2002**

In connection with the annual report of Enable Midstream Partners, LP (the Partnership) on Form 10-K for the period ended December 31, 2019, as filed with the Securities and Exchange Commission (the Report), I, Rodney J. Sailor, President and Chief Executive Officer of Enable GP, LLC, the general partner of the Partnership, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

1. The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Partnership.

Date: February 19, 2020

/s/ Rodney J. Sailor

Rodney J. Sailor

President and Chief Executive Officer, Enable GP, LLC, the General Partner of Enable Midstream Partners, LP

(Principal Executive Officer)

Exhibit 32.2

CERTIFICATION PURSUANT TO 18 U.S.C. SECTION 1350
AS ADOPTED PURSUANT TO SECTION 906
OF THE SARBANES-OXLEY ACT OF 2002

In connection with the annual report of Enable Midstream Partners, LP (the Partnership) on Form 10-K for the period ended December 31, 2019, as filed with the Securities and Exchange Commission (the Report), I, John P. Laws, Executive Vice President, Chief Financial Officer, and Treasurer of Enable GP, LLC, the general partner of the Partnership, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

1. The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Partnership.

Date: February 19, 2020

/s/ John P. Laws

John P. Laws

Executive Vice President, Chief Financial Officer and Treasurer, Enable GP, LLC,
the General Partner of Enable Midstream Partners, LP

(Principal Financial Officer)