Enable Midstream Partners, LP
Form 10-K
February 17, 2016
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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 10-K

þ ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF
THE SECURITIES AND EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2015
or
¨ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF
THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from _____to_____
Commission File No. 1-36413

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

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

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

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

Title of each class	Name of each exchange on which registered
Common Units Representing Limited Partner Interests	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act: None
Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.
þ Yes o No
Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or 15(d) of the Act.
o Yes þ No
Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. þ Yes ¨ No
Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). þ Yes ¨ No

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

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

Large accelerated filer	þ		Accelerated filer	¨
Non-accelerated filer	¨	(Do not check if a smaller reporting company)	Smaller reporting company	¨

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

The aggregate market value of the Common Units representing limited partner interests held by non-affiliates of the registrant, based upon the closing price of $15.98 per common limited partner unit on June 30, 2015, was approximately $1,242 million.

As of February 1, 2016, there were 214,541,450 common units and 207,855,430 subordinated units outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

None

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GLOSSARY

2011 Pipeline Safety Act.	Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011.
Adjusted EBITDA.	A non-GAAP measure calculated as net income from continuing operations before interest expense, income tax expense, depreciation and amortization expense and certain other items management believes affect the comparability of operating results.
APSA.	Accountable Pipeline Safety and Partnership Act of 1996.
ArcLight.	ArcLight Capital Partners, LLC, a Delaware limited liability company, its affiliated entities ArcLight Energy Partners Fund V, L.P., ArcLight Energy Partners Fund IV, L.P., Bronco Midstream Partners, L.P., Bronco Midstream Infrastructure LLC and Enogex Holdings LLC, and their respective general partners and subsidiaries.
ASU.	Accounting Standards Update.
Atoka.	Atoka Midstream LLC, in which the Partnership owns a 50% interest as of December 31, 2015, which provides gathering and processing services.
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.
CenterPoint Energy.	CenterPoint Energy, Inc., a Texas corporation, and its subsidiaries, other than Enable Midstream Partners, LP for periods prior to formation of the Partnership on May 1, 2013.
CERCLA.	Comprehensive Environmental Response, Compensation and Liability Act of 1980.
CFTC.	Commodity Futures Trading Commission.
CO2e.	Carbon dioxide equivalent.
Code.	The Internal Revenue Code of 1986, as amended.
Condensate.	A natural gas liquid with a low vapor pressure, mainly composed of propane, butane, pentane and heavier hydrocarbon fractions.
Delaware Act.	Delaware Revised Uniform Limited Partnership Act.
DHS.	Department of Homeland Security.
Dodd-Frank Act.	Dodd-Frank Wall Street Reform and Consumer Protection Act.
DOT.	Department of Transportation.
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 and Kansas.
EIA.	Energy Information Administration.
EIIT.	Enable Illinois Intrastate Transmission, LLC, a wholly owned subsidiary of the Partnership that operates a 20-mile intrastate pipeline that provides natural gas transportation and storage services to customers in Illinois.
Enable GP.	Enable GP, LLC, a Delaware limited liability company and the general partner of Enable Midstream Partners, LP.
Enable Midstream Services.	Enable Midstream Services, LLC, a wholly owned subsidiary of the Partnership that provides employee management services to the Partnership.
Enogex.	Enogex LLC, a Delaware limited liability company, and its subsidiaries.

EOIT.	Enable Oklahoma Intrastate Transmission, LLC, formerly Enogex LLC, a wholly owned subsidiary of the Partnership that operates a 2,200-mile intrastate pipeline that provides natural gas transportation and storage services to customers in Oklahoma.
ESA.	Endangered Species Act.

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EPA.	Environmental Protection Agency.
EPAct of 2005.	Energy Policy Act of 2005.
ERISA.	Employee Retirement Income Security Act of 1974.
Exchange Act.	Securities Exchange Act of 1934, as amended.
FASB.	Financial Accounting Standards Board.
FERC.	Federal Energy Regulatory Commission.
Fractionation.	The separation of the heterogeneous mixture of extracted NGLs into individual components for end-use sale.
GAAP.	Generally accepted accounting principles in the United States.
Gas imbalance.	The difference between the actual amounts of natural gas delivered from or received by a pipeline, as compared to the amounts scheduled to be delivered or received.
General partner.	Enable GP, LLC, a Delaware limited liability company, the general partner of Enable Midstream Partners, LP.
GHG.	Greenhouse gas.
Gross margin.	A non-GAAP measure calculated as revenues minus cost of natural gas and natural gas liquids, excluding depreciation and amortization.
HCA.	High-consequence area.
HLPSA.	Hazardous Liquid Pipeline Safety Act of 1979.
Hinshaw pipeline.	A pipeline that is exempt from FERC's NGA regulation if its operations are within a single state, if any gas received from interstate sources is received within the state and if its service is regulated by the state commission.
ICA.	Interstate Commerce Act.
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 without NGLs.
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.
MFA.	Master Formation Agreement dated as of March 14, 2013.
MMcf.	Million cubic feet of natural gas.
MMBtu.	Million British thermal units.
MMcf/d.	Million cubic feet per day.
MOP.	Maximum operating pressure for hazardous liquid pipelines.
MRT.	Enable Mississippi River Transmission, LLC, a wholly owned subsidiary of the Partnership that operates a 1,700-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.
NGPA.	Natural Gas Policy Act of 1978.
NGPSA.	Natural Gas Pipeline Safety Act of 1968.
NGLs.	Natural gas liquids, which are the hydrocarbon liquids contained within natural gas including condensate.
NYMEX.	New York Mercantile Exchange.
NYSE.	New York Stock Exchange.
OCC.	Oklahoma Corporation Commission.

Offering.	Initial public offering of Enable Midstream Partners, LP.

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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.
PDO.	Petition for a Declaratory Order. Petition filed with FERC to seek regulatory assurances for key terms of service offered during an open season.
PHMSA.	Pipeline and Hazardous Materials Safety Administration.
PIPES Act.	Pipeline Inspection, Protection, Enforcement, and Safety Act of 2006.
Preferred Units.	10% Series A Fixed-to-Floating Non-Cumulative Redeemable Perpetual Preferred Units representing limited partner interests in the Partnership.
Private Placement.	An agreement with CenterPoint Energy, dated January 28, 2016 to issue and sell an aggregate of 14,520,000 Preferred Units.
PSA.	Pipeline Safety Act of 1992.
PSIA.	Pipeline Safety Improvement Act of 2002.
PVIR.	Preventable Vehicle Incident Rate.
RCRA.	Resource Conservation and Recovery Act of 1976.
Revolving Credit Facility	$1.75 billion senior unsecured revolving credit facility
RICE MACT.	Reciprocating internal combustion engines maximum achievable control technology.
Rich gas.	Natural gas containing higher concentrations of NGLs that is usually produced in association with crude oil.
SCOOP.	South Central Oklahoma Oil Province.
SDWA.	Safe Drinking Water Act.
SEC.	Securities and Exchange Commission.
Securities Act.	Securities Act of 1933, as amended.
SESH.	Southeast Supply Header, LLC, in which the Partnership owns a 50% interest as of December 31, 2015, 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.
Term Loan Facilities.	$450 million unsecured term loan facility dated July 31, 2015 (2015 Term Loan Facility) and $1.05 billion unsecured term loan facility dated May 1, 2013 (2013 Term Loan Facility).
TRIR.	Total Recordable Incident Rate.
WTI.	West Texas Intermediate.
2019 Notes.	$500 million 2.400% senior notes due 2019.
2024 Notes.	$600 million 3.900% senior notes due 2024.
2044 Notes.	$550 million 5.000% senior notes due 2044.

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FORWARD-LOOKING STATEMENTS

Some of the information in this report may contain forward-looking statements within the meaning of Section 27A of the Securities Act and Section 21E of the Exchange Act. 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, "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;
- operating hazards and other risks incidental to transporting, storing and gathering natural gas, NGLs, crude oil and midstream products;
- natural disasters, weather-related delays, casualty losses and other matters beyond our control;
- interest rates;
- 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 future litigation; and
- other factors set forth in this report and our other filings with the SEC.

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

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PART I

Item 1. Business

Overview

We are a large-scale, growth-oriented publicly traded Delaware limited partnership formed to own, operate and develop strategically located natural gas and crude oil infrastructure assets. We serve current and emerging production areas in the United States, including several unconventional shale resource plays, and local and regional end-user markets in the United States. Our assets and operations are organized into two reportable segments: (i) Gathering and Processing, which primarily provides natural gas gathering, processing and fractionation services and crude oil gathering for our producer customers, and (ii) Transportation and Storage, which provides interstate and intrastate natural gas pipeline transportation and storage services primarily to natural gas producers, utilities and industrial customers.

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

We were formed in May 2013 as a limited partnership among CenterPoint Energy, OGE Energy and ArcLight, then completed the Offering to become publicly traded in April 2014. As of December 31, 2015, our portfolio of energy infrastructure assets included approximately 12,400 miles of gathering pipelines, 13 major processing plants with approximately 2.3 Bcf/d of processing capacity, approximately 7,900 miles of interstate pipelines (including SESH), approximately 2,200 miles of intrastate pipelines and eight natural gas storage facilities providing approximately 85.0 Bcf of storage capacity. Based on our scale, we believe we are able to provide our customers with fully integrated midstream services from the wellhead to the marketplace.

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

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 soon after we file or furnish such material.

Business Strategies

Our primary business objective is to practice commercial and operational excellence and to grow our business responsibly, enabling us to increase the amount of cash available for distributions we make to our unitholders over time while maintaining our financial stability. We intend to accomplish this objective by executing the strategies listed below:

- Capitalize on Organic Growth Opportunities Associated with Our Strategically Located Assets. We own and operate assets servicing four of the largest basins in the United States, including some of the most productive shale plays in these basins. We intend to grow our business and cash available for distribution by developing new midstream infrastructure projects to support new and existing customers if they expand beyond our current footprint. As a result of this strategy, we completed the Bradley Plant, a 200 MMcf/d processing facility located in Grady County, Oklahoma, during the first quarter of 2015. We are constructing two cryogenic processing facilities to connect to our super-header system in Grady County, Oklahoma and Garvin County, Oklahoma, which are expected to add 400 MMcf/d of combined natural gas processing capacity. The first of the two new plants (the Bradley II Plant, formerly referred to as the Grady County Plant) is a 200 MMcf/d plant which is expected to be completed in the second quarter of 2016. The second plant (the Wildhorse Plant) is a 200 MMcf/d plant that is expected to be completed in late 2017. To support these new processing facilities and other organic growth opportunities, we are also constructing natural gas gathering and compression infrastructure, natural gas transportation infrastructure and crude oil gathering infrastructure. In 2015, we finalized contracts for an expansion of EGT's Line AD which will result in 75 MMcf/d of firm capacity deliveries to the Perryville Hub and Bennington, Oklahoma. For the year ended December 31, 2015, we invested $789 million in expansion capital expenditures, including the $80 million acquisition of assets from Monarch Natural Gas, LLC.

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- Continue to Minimize Direct Commodity Price Exposure Through Long-Term, Fee-Based Contracts. We continually seek ways to minimize our exposure to commodity price risk, and management believes that our focus on fee-based revenues reduces our direct commodity price exposure and is essential to maintaining stable cash flows and increasing our quarterly distributions over time. For the year ended December 31, 2015, 81% of our gross margin was generated from fee-based contracts. As we grow, we intend to maintain our focus on increasing the percentage of long-term, fee-based contracts with our customers.
- Maintain Strong Customer Relationships to Attract New Volumes and Expand Beyond Our Existing Asset Footprint and Business Lines. We plan to grow our business through our strong relationships with existing customers. Management believes that we have built a strong and loyal customer base through exemplary customer service and reliable project execution. We have invested in several organic growth projects in support of our existing and new customers. We work to maintain and build relationships with key producers and suppliers in an effort to attract new volumes and expansion opportunities.
- Grow Through Accretive Acquisitions and Disciplined Development. We plan to pursue accretive acquisitions of complementary assets that provide attractive potential returns in new operating regions or midstream business lines. We will continue to analyze acquisition opportunities using disciplined financial and operating practices, including a process for evaluating and managing risks to cash distributions.
- Leverage the Scale of Our Existing Assets to Realize Synergies. Given the complementary features of our assets, we expect operating synergies from the interconnection and optimization of our systems to increase our cash flows over time.

Our Sponsors

As of December 31, 2015, CenterPoint Energy and OGE Energy own a significant interest in us through their approximate 55.4% and 26.3% limited partner interests in us, respectively. CenterPoint Energy and OGE Energy each own 50% of the management rights of our general partner, which holds all of our incentive distribution rights. In addition, CenterPoint Energy and OGE Energy own 40% and 60%, respectively, of the economic rights in our general partner.

On January 28, 2016, we entered into an agreement with CenterPoint Energy to issue and sell in a Private Placement an aggregate of 14,520,000 Preferred Units. The Private Placement is expected to close prior to the end of the first quarter of 2016, subject to certain closing conditions. For a further discussion regarding the Private Placement, see Item 7. “Management’s Discussion and Analysis of Financial Condition and Results of Operation - Liquidity and Capital Resources - Equity Issuances.”

CenterPoint Energy (NYSE: CNP) is a public utility holding company whose indirect wholly owned subsidiaries include (i) CenterPoint Energy Houston Electric, LLC, which provides electric transmission and distribution services to retail electric providers serving over two million metered customers in a 5,000-square- mile area of the Texas Gulf Coast that has a population of approximately six million people and includes the city of Houston; and (ii) CenterPoint Energy Resources Corp., which owns and operates natural gas distribution systems serving more than three million customers in six states, including customers in the metropolitan areas of Houston, Texas; Minneapolis, Minnesota; Little Rock, Arkansas; Shreveport, Louisiana; Biloxi, Mississippi; and Lawton, Oklahoma.

OGE Energy (NYSE: OGE) is the parent company of OG&E, a regulated electric utility serving approximately 825,000 customers in a service territory spanning 30,000 square miles in Oklahoma and western Arkansas. OG&E furnishes retail electric service in 267 communities and their contiguous rural and suburban areas. OG&E’s service area includes Oklahoma City, Oklahoma and Fort Smith, Arkansas, the second largest city in that state. Of the 267 communities that OG&E serves, 241 are located in Oklahoma and 26 are located in Arkansas.

Our sponsors are also significant customers of our transportation and storage segment and continue to own and operate a substantial portfolio of energy assets. For the year ended December 31, 2015, approximately 3% of our total gross margin was derived from contracts with OGE Energy servicing electric power generation. For the year ended December 31, 2015, approximately 7% of our total gross margin was derived from contracts servicing LDCs owned by CenterPoint Energy.

Our sponsors entered into a number of agreements in connection with our formation. Please read Item 13. “Certain Relationships and Related Party Transactions” for a detailed description of these agreements, as well as other agreements affecting us and our sponsors. 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.

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Our Assets and Operations

Our assets and operations are organized into two reportable segments: Gathering and Processing, and Transportation and Storage.

Gathering and Processing

General. We own and operate approximately 12,400 miles of natural gas gathering pipelines in the Anadarko, Arkoma and Ark-La-Tex basins with approximately 976,000 horsepower of compression and 13 natural gas processing plants with approximately 2.3 Bcf/d of processing capacity and 2.3 Bcf/d of treating capacity as of December 31, 2015. We provide gathering, compression, treating, dehydration, processing and NGL fractionation for producers who are active in the areas in which we operate. For the year ended December 31, 2015, our assets gathered an average of approximately 3.14 TBtu/d of natural gas. For the year ended December 31, 2015, we processed approximately 1.78 TBtu/d of natural gas and produced approximately 73.55 MBbl/d of NGLs. We also have a crude oil gathering business in the Bakken Shale formation, principally located in the Williston Basin, that commenced initial operations in November 2013.

We serve shale developments in the United States through our operations in the following basins:

- Anadarko Basin (Oklahoma, Texas Panhandle). We currently operate in the liquids-rich Granite Wash, Cleveland, Tonkawa, Cana Woodford, SCOOP, STACK and Mississippi Lime plays. As of December 31, 2015, our assets include approximately 7,700 miles of natural gas gathering pipelines and ten natural gas processing plants with approximately 1.6 Bcf/d of processing capacity. We also have two processing plants under construction that will add 400 MMcf/d of processing capacity. For the year ended December 31, 2015, this system had average daily gathered throughput of approximately 1.59 TBtu/d of natural gas and produced 58.50 MBbl/d of NGLs. We currently serve over 200 producers in these areas and have secured 4.6 million gross acres dedicated under fee-based long-term contracts in this basin. These contracts provide for gathering and compression services, which are typically fee-based, and processing services under fee-based, percent-of-liquids, percent-of-proceeds or keep-whole structures.
- Arkoma Basin (Oklahoma, Arkansas). In Oklahoma, we operate in the rich and lean gas areas of the western portion of the Arkoma basin. In Arkansas, we operate in the eastern Arkoma and the Fayetteville Shale play. As of December 31,

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2015, our assets include approximately 3,000 miles of natural gas gathering pipelines and one natural gas processing plant with approximately 60 MMcf/d of processing capacity. For the year ended December 31, 2015, this system had average daily gathered throughput of approximately 0.67 TBtu/d of natural gas and produced 4.98 MBbl/d of NGLs. We currently serve over 80 producers in these areas and have secured over 1.4 million gross acres dedicated under long-term contracts in this basin. Additionally, in the lean gas area of the Fayetteville Shale we have secured fee-based contracts that provide minimum revenues in time periods when natural gas prices are depressed.

- Ark-La-Tex Basin (Arkansas, Louisiana and Texas). In Arkansas, Louisiana, and Texas, we operate primarily in the Haynesville, Cotton Valley and the lower Bossier plays. As of December 31, 2015, our assets include approximately 1,700 miles of natural gas gathering pipelines, two natural gas processing plants with approximately 545 MMcf/d of processing capacity, an NGL fractionation facility and approximately 40 miles of ethane pipelines. For the year ended December 31, 2015, this system had average daily gathered throughput of approximately 0.88 TBtu/d of natural gas and produced 10.07 MBbl/d of NGLs. We currently serve over 90 producers in these areas and have secured over 0.7 million gross acres dedicated under long-term contracts in this basin. Additionally, in the lean gas area of the Haynesville Shale we have secured contracts that contain minimum volume commitment features, providing minimum revenues in periods of time when natural gas prices are depressed.
- Williston Basin (North Dakota). In November 2013, we commenced operations on our initial crude oil gathering pipeline system, located in Dunn and McKenzie Counties in North Dakota, within the Bakken Shale formation. Additionally, in February 2014, we executed an agreement to gather crude oil production through a new system in Williams and Mountrail Counties in North Dakota which commenced operations in the second quarter of 2015. The remaining portion of the system is expected to be placed in service during 2016 and 2017. These systems will have a combined capacity of 49,500 barrels per day. A portion of these systems have contracts that contain minimum volume commitment features, providing minimum revenues when crude oil prices are depressed, and the remaining portion of these systems are supported by over 0.2 million gross acres dedicated under long-term contracts with XTO Energy Inc. (XTO), an affiliate of Exxon Mobil Corporation, to provide crude oil gathering along with water transportation and other complementary services. For the year ended December 31, 2015, these crude oil gathering systems had average daily throughput of approximately 13.9 MBbl/d.

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

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

Asset/Basin	Approximate Length (miles)	Approximate Compression (Horsepower)	Average Gathering Volume (TBtu/d)	Number of Processing Plants	Processing Capacity (MMcf/d)	NGLs Produced (MBbl/d)	Gross Acreage Dedications (in millions)
Anadarko Basin	7,700	690,600	1.59	10	1,645	58.50	4.6
Arkoma Basin	3,000	135,800	0.67	1	60	4.98	1.4

Ark-La-Tex Basin(1)	1,700	150,000	0.88	2	545	10.07	0.7
Total	12,400	976,400	3.14	13	2,250	73.55	6.7

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

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The following table sets forth information with respect to our natural gas processing plants as of or for the year ended December 31, 2015:

Processing Plant	Year Installed		Type of Plant	Average Daily Inlet Volumes (MMcf/d)	Inlet Capacity (MMcf/d)	NGL Production Capacity (Bbl/d)(1)
Anadarko						
Wildhorse	2017	(2)	Cryogenic	—	200	28,000
Bradley II	2016	(2)	Cryogenic	—	200	28,000
Bradley	2015		Cryogenic	144	200	28,000
McClure	2013		Cryogenic	186	200	22,000
Wheeler	2012		Cryogenic	196	200	22,000
South Canadian	2011		Cryogenic	169	200	26,000
Clinton	2009		Cryogenic	123	120	14,000
Roger Mills(3)	2008		Refrigeration	30	100	—
Canute	1996		Cryogenic	37	60	4,300
Cox City	1994		Cryogenic	127	180	14,500
Thomas	1981		Cryogenic	49	135	9,900
Calumet	1969		Lean Oil	105	250	8,000
Arkoma						
Wetumka	1983		Cryogenic	30	60	5,000
Ark-La-Tex						
Sligo(4)	2004		Refrigeration	50	225	1,400
Waskom	1995	(5)	Cryogenic	222	320	14,500
Total				1,468	2,650	225,600

(1) Excludes condensate capacity.

(2) The Bradley II Plant is under construction and estimated to be in service in the second quarter of 2016. The Wildhorse Plant is under construction and estimated to be in service in late 2017.

(3) All of our processing plants are located on properties that are owned by us except for Roger Mills, which is located on property that is leased.

(4) Average daily inlet volumes and inlet capacity includes 22 MMcf/d and 25 MMcf/d, respectively, related to a separate cryogenic unit.

(5) A processing plant has been in operation on the Waskom plant site since 1940. The Waskom plant was upgraded to cryogenic in 1995.

Off-System Delivery Points. Our gathering lines interconnect with both our interstate and intrastate pipelines, as well as other interstate and intrastate pipelines, including the Acadian, ANR, ETC Tiger, Gulf Crossing, Gulf South, NGPL, Northern Natural, Panhandle Eastern, Regency, SONAT, Tennessee Gas and Texas Eastern Transmission pipelines. These connections provide producers with access to a diverse set of natural gas market hubs.

Substantially all of our NGLs are delivered into third-party pipelines and transported to Conway, Kansas, or Mont Belvieu, Texas, where the NGLs are sold under contract or on the spot market. We sell propane to local markets at the tailgate of three of our processing plants. Additionally, at our Waskom processing plant, we operate a full NGL fractionator and an ethane pipeline and sell ethane, propane, butane and natural gasoline to local markets. Ethane from Waskom is sold via our pipeline to a local petrochemical producer.

Processed natural gas is predominantly returned to the producer customers into our pipelines for redelivery either to on-system customers, such as electric generation facilities and other end-users, or into downstream interstate pipelines. NGLs are typically sold to NGL marketers and end-users, and condensate liquid production is typically sold to marketers and refineries.

Customers. We generate revenues from producers in the basins in which we operate. For the year ended December 31, 2015, our top gathering and processing customers by volumes gathered were affiliates of Continental Resources, Inc. (Continental), XTO, Vine Oil and Gas (Vine), Chesapeake Energy Corporation (Chesapeake), GeoSouthern Energy Corporation (GeoSouthern), Apache Corporation (Apache), Covey Park Energy LLC (Covey Park), Devon Energy Corporation (Devon), Tapstone Energy

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LLC (Tapstone) and BP America Production Company (BP). For the year ended December 31, 2015, our top ten natural gas producer customers accounted for approximately 65% of our gathered volumes. The amounts for GeoSouthern reflect its acquisition of 100% of Encana Corporation's Haynesville Shale assets in Louisiana during the fourth quarter of 2015, which included the assignment of our associated long term gas gathering and treating agreements.

Contracts. We derive revenue pursuant to a variety of arrangements. For the year ended December 31, 2015, 48%, 47% and 5%, of our processing arrangements were fee-based, percent-of-proceeds or percent-of-liquids, and keep-whole, respectively.

For the year ended December 31, 2015, 72% of our gathering and processing gross margin was generated from gathering and processing fees. The remaining 28% of gross margin for the year ended December 31, 2015 came from sales of commodities, including natural gas, natural gas liquids, and condensate received under percent-of-proceeds, percent-of-liquids and keep-whole arrangements. For the year ended December 31, 2015, contracts generating 34% of our gathering and processing gross margin had minimum volume commitment features with remaining terms ranging from 2 to 12 years. Under a minimum volume commitment, a customer commits to ship a minimum volume of natural gas over a period of time on our gathering system, or, in lieu of shipping such volumes, to pay as if that minimum amount had been shipped.

As of December 31, 2015, our gathering agreements had acreage dedications with original terms ranging up to 15 years, which generally require that production by our customers within the acreage dedication be delivered to our gathering systems. As of December 31, 2015, our natural gas gathering agreements had acreage dedications of 6.7 million gross acres with a volume-weighted average remaining term of approximately seven years. In addition, as of December 31, 2015, we had minimum volume commitment features in lean natural gas developments of 2.1 Bcf/d with committed volume-weighted average remaining terms of approximately 6 years.

We have the ability to enhance gross margin generated from our gathering and processing contracts through the use of multiple processing plant locations and our super-header system. Our large diameter, rich gas gathering pipelines in western Oklahoma are configured to allow natural gas from western Oklahoma and the Wheeler County area in the Texas Panhandle to flow to the Bradley, Cox City, Thomas, McClure, Calumet, Clinton, South Canadian and Wheeler processing plants, and we have the ability to maximize margins from our contracts by choosing the most economical operational configuration given the market conditions at the time, including ethane rejection scenarios.

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

Transportation and Storage

We provide fee-based interstate and intrastate transportation and storage services across nine states. We own and operate approximately 7,900 miles (including SESH) of interstate transportation pipelines with average firm contracted capacity of 7.19 Bcf/d (excluding SESH), for the year ended December 31, 2015. In addition, we own and operate approximately 2,200 miles of intrastate transportation pipelines with average aggregate throughput of 1.84 TBtu/d for the year ended December 31, 2015.

We also own and operate eight natural gas storage facilities with approximately 85.0 Bcf of aggregate capacity and approximately 1.9 Bcf/d of aggregate daily deliverability as of December 31, 2015. In addition, we own an 8% contractual interest in Gulf South’s Bistineau storage facility located in Bienville Parish, Louisiana, with 8.0 Bcf of capacity and 100 MMcf/d of deliverability as of December 31, 2015. We also contract on a firm basis for 3.3 Bcf of high deliverability salt dome storage capacity from Cardinal in the Perryville and Arcadia natural gas storage fields. Our storage operations are located in Louisiana, Oklahoma and Illinois.

Both our intrastate and interstate storage facilities benefit customers by providing a full suite of storage services including no notice, load-following storage services and pipeline balancing. Our storage revenues are primarily fee-based and are derived from both firm and interruptible contracts. These contracts are often combined with transportation agreements to provide an overall solution for our customers. Our intrastate storage assets offer both fee-based firm and interruptible storage services. Interstate storage services offered by our intrastate storage facilities are provided at market-based rates under Section 311 of the NGPA pursuant to terms and conditions specified in our statements of operating conditions.

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

Asset	Length (miles)	Capacity		Total Firm Contracted Capacity(Bcf/d)	Average Throughput Volume (TBtu/d)		Percent of Capacity under Firm Contracts		Weighted Average Remaining Firm Contract Life(years)
Interstate Transportation[1]	7,900	8.4	Bcf /d	7.19	3.1	[2]	86	%	3.3
Intrastate Transportation	2,200	2.1	Bcf /d[3]	—	1.8		—		5.5
Storage	—	85.0	Bcf	64.69	—		76	%	3.5

(1) Except with respect to length, this information does not include amounts for SESH. SESH is a non-consolidated entity in which we own a 50% ownership interest.

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

(3) This represents the maximum single day receipts on the intrastate systems. 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, 2015, the peak daily throughput was 2.1 TBtu/d or, on a volumetric basis, 2.1 Bcf/d.

We divide our transportation and storage assets into three categories: (1) interstate pipelines, (2) intrastate pipelines, and (3) storage. Our interstate pipelines consist of EGT, MRT and a 50% interest in the SESH pipeline. Our intrastate pipelines include the EOIT pipeline and the EIIT pipeline, which is operated commercially in conjunction with MRT.

Our transportation and storage assets were designed and built to serve large natural gas and electric utility companies in our areas of operation. For the year ended December 31, 2015, our top customers by gross margin were affiliates of CenterPoint Energy, Laclede Gas Company (Laclede), XTO, OGE Energy, American Electric Power Co. (AEP), Chesapeake, EOG Resources, Inc. (EOG), Midcontinent Express Pipeline LLC (Midcontinent), Entergy Corporation (Entergy) and Continental. Our EGT pipeline connects to our SESH pipeline in Perryville, Louisiana, where we perform our Perryville Hub™ services, which provides access to natural gas supplies from the Midcontinent, North Louisiana and East Texas and to natural gas-consuming markets in the Southeast, Northeast and Midwestern United States.

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Interstate Transportation

The following table sets forth certain information regarding our interstate transportation pipeline assets as of December 31, 2015:

Interstate Pipelines[1]

Asset	Length (miles)	Compression (Horsepower)	Average Throughput (TBtu/d)	Capacity (Bcf/d)	Storage Capacity (Bcf)
EGT	5,900	383,200	2.4	6.5	29.5
MRT	1,700	118,600	0.7	1.9	31.5
Total	7,600	501,800	3.1	8.4	61.0

(1) Excludes SESH, which is accounted for as an equity investment and described under "—Other Assets" below.

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EGT

General. EGT is 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 and Kansas. The system has the capacity to transport 6.5 Bcf/d of natural gas as of December 31, 2015. During the year ended December 31, 2015, we transported an average of approximately 2.4 TBtu/d, on this system. The system has pipeline diameters ranging from one to 42 inches and has 48 compressor stations. The system also had 29.5 Bcf of natural gas storage capacity as of December 31, 2015.

Off-System Delivery Points. Shippers on EGT have the ability to access almost every major natural gas-consuming market east of the Mississippi River. These include the growing Southeast power generation sector via SESH, as well as the ANR, Columbia Gulf, Gulf South, Midcontinent Express (MEP), MRT, SONAT, Tennessee Gas, Texas Eastern, Texas Gas and Trunkline pipelines, which are interconnected with EGT at Perryville, Louisiana, giving customers access to consuming markets in the Northeast and Midwest United States via our Perryville Hub™ services.

Customers. The primary customers for our EGT system are the local gas distribution affiliates of CenterPoint Energy, gas producers who hold contracts for their Barnett and Haynesville Shale production, gas-fired power generators and other industrial and local third-party distribution companies. For the year ended December 31, 2015, approximately 28% of EGT’s total operating gross margin was attributable to services provided to subsidiaries of CenterPoint Energy. EGT’s customers are primarily located in Arkansas, Louisiana, Oklahoma and Texas.
Contracts. EGT’s services are typically provided under firm storage and transportation agreements. For the year ended December 31, 2015, approximately 54% of total transportation and storage segment gross margins were derived from demand charges under EGT’s firm contract arrangements. As of December 31, 2015, approximately 85% of EGT’s capacity was under contract with an average remaining contract life of 3.4 years. The primary terms of EGT’s firm transportation and storage contracts with CenterPoint Energy will begin to expire in 2018, with the majority of the contracts expiring in 2021.

EGT established maximum rates for interstate transportation and storage services on its system as required by FERC, though EGT is authorized to enter into negotiated rate and discounted rate agreements with customers. In October 2012, we initiated a process with EGT’s customers to reach an agreed-upon rate, or settlement rate, that will allow us to recover on the increased costs associated with maintaining a safe and reliable system. These discussions have been discontinued and EGT is under no obligation to initiate a rate proceeding by a date certain.

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Storage. EGT's storage assets include two underground natural gas storage facilities in Oklahoma and one underground natural gas storage facility in Louisiana, which operate at a combined capacity of 29.5 Bcf with 674 MMcf/d of aggregate maximum withdrawal capacity as of December 31, 2015.

MRT

General. MRT is a 1,700-mile interstate pipeline that provides natural gas transportation and storage services principally in Texas, Arkansas, Louisiana, Missouri and Illinois. This system provides market access for producers from the Haynesville and Fayetteville Shale plays. The system could transport 1.9 Bcf/d of natural gas as of December 31, 2015. For the year ended December 31, 2015, we transported an average of approximately 0.7 TBtu/d on this system. The system has various pipeline diameters ranging up to 30 inches and has 15 compressor stations. The system also had 31.5 Bcf of working natural gas storage capacity as of December 31, 2015.

Delivery Points. MRT's primary delivery points are to LDCs and industrial markets in the St. Louis market area. MRT's shippers access natural gas at Perryville, Louisiana and East Texas markets and, via EGT interconnects, the Mid-Continent.

Customers. MRT derives a significant portion of its gross margin from an affiliate of Laclede, the local natural gas distribution company serving the St. Louis market area, which comprised 78% of MRT's gross margin for the year ended December 31, 2015. MRT's other customers include subsidiaries of Ameren, subsidiaries of CenterPoint Energy and other industrial companies. MRT's customers are primarily located in Arkansas, Illinois and Missouri.

Contracts. MRT's services to its customers are typically provided under firm storage and transportation agreements. For the year ended December 31, 2015, approximately 14% of total transportation and storage segment gross margins were derived from demand charges under MRT's firm contract arrangements. As of December 31, 2015, approximately 89% of MRT's capacity was under contract with an average remaining contract life of 2 years. MRT's firm transportation and storage contracts with Laclede are scheduled to expire in 2017 and 2018.

Storage. MRT's storage assets include two underground natural gas storage facilities in Louisiana and one underground

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natural gas storage facility in Illinois, which operate at a combined capacity of 31.5 Bcf with 620 MMcf/d of aggregate maximum withdrawal capacity as of December 31, 2015.

Other Assets

SESH is an approximately 290-mile interstate pipeline that provides natural gas transportation services. We own a 50% interest in SESH and operate the pipeline. The remaining 50% of SESH is owned by Spectra Energy Partners, LP.

The SESH pipeline runs from Perryville, Louisiana, to southwestern Alabama near the Gulf Coast, where most of the gas transported by the pipeline is then transported by third-party pipelines to companies generating electricity for the Florida power market. As of December 31, 2015, the system could transport 1.6 Bcf/d of natural gas from Perryville to Gwinville, Mississippi, and 1.08 Bcf/d of natural gas to the pipeline's end point in Alabama. During the year ended December 31, 2015, an average of approximately 1.5 Bcf/d was transported on this system. The system has pipeline diameters ranging from 16 to 42 inches and has 6 compressor stations.

The SESH pipeline has 20 interconnections with existing natural gas pipelines and access to three high deliverability storage facilities: Mississippi Hub Storage, Petal Gas Storage and Southern Pines Energy Center.

The primary customers for the SESH pipeline are companies that generate electricity using natural gas in the Florida market area. The rates charged by SESH for interstate transportation services are regulated by FERC. Service on SESH is largely provided under long-term, negotiated rate agreements with customers.

Competition

Our interstate pipelines compete with other interstate and intrastate pipelines. The principal elements of competition among pipelines are rates, terms of service, and flexibility and reliability of service.

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Intrastate Transportation

General. Our intrastate pipelines consist of approximately 2,200 miles of intrastate transportation pipeline in Oklahoma with 1.84 TBtu/d of average daily throughput for the year ended December 31, 2015 and approximately 20 miles of intrastate transportation pipeline in Illinois. Our intrastate systems deliver natural gas from the Arkoma and Anadarko basins, including growth activity in the Cana Woodford, Granite Wash, Cleveland, Tonkawa, SCOOP, STACK and Mississippi Lime Shale plays in western Oklahoma and the Texas Panhandle, to interstate and intrastate pipelines and end users.

Delivery Points. Our intrastate pipelines are connected to our EGT system and 12 third-party natural gas pipelines and have 67 interconnect points. These third-party natural gas pipelines include ANR Pipeline, El Paso Natural Gas Pipeline, Gulf Crossing Pipeline Company LLC, Midcontinent Express Pipeline (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 Western Trails. In addition, our intrastate pipelines are connected to 36 end-user customers, including 14 natural gas-fired electric generation facilities in Oklahoma.

Customers. Our major transportation customers are OG&E, our affiliate, and Public Service Company of Oklahoma, an affiliate of AEP (PSO), the two largest electric utilities in Oklahoma. We provide gas transmission delivery services to the majority of OG&E’s and all of PSO’s natural gas-fired electric generation facilities in Oklahoma under firm intrastate transportation contracts. Customer demand for natural gas on our system is usually greater during the summer, primarily due to demand by natural gas-fired electric generation facilities to serve residential and commercial electricity requirements.

Contracts. The intrastate pipelines provide fee-based firm and interruptible transportation services on both an intrastate basis and, pursuant to Section 311 of the NGPA, on an interstate basis. Transportation services are offered under Section 311 of the NGPA pursuant to terms and conditions specified in our statement of operating conditions for natural gas transportation. Our intrastate pipelines derive a substantial portion of gross margins from firm transportation services subject to reservation charges. To the extent pipeline capacity is not needed for such firm transportation services and contracted capacity, we offer interruptible transportation services.

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For the year ended December 31, 2015, approximately 18% of our total transportation and storage segment gross margins were derived from demand charges under firm contract arrangements for our intrastate pipelines with an average remaining contract life of 5.1 years. Our contracts with PSO and OG&E provide for a monthly demand charge plus variable transportation charges including fuel. Our transportation agreement with PSO is on a one-year renewal term and has been extended through January 1, 2017. Our transportation agreement with OG&E extends through April 30, 2019, 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.

Storage. Our intrastate storage assets include two underground natural gas storage facilities in Oklahoma, which operate at a combined capacity of 24 Bcf with 605 MMcf/d of aggregate maximum withdrawal capacity as of December 31, 2015.

Competition

Our intrastate pipeline system competes with numerous interstate and intrastate pipelines, including several of the interconnected pipelines discussed above, as well as other natural gas storage facilities. The principal elements of competition are rates, terms of services, flexibility and reliability of service. Natural gas-fired electric generation facilities contribute their highest value when they have the capability to provide load following service to the customer (i.e., the ability of the generation facility to regulate generation to respond to and meet the instantaneous changes in customer demand for electricity). While the physical characteristics of natural gas-fired electric generation facilities are known to provide quick start-up, on-line functionality and the ability to efficiently provide varying levels of electric generation relative to other forms of generation, a key part of their effectiveness is contingent upon having access to an integrated pipeline and storage system that can respond quickly to meet their corresponding fluctuating fuel needs.

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

Our interstate pipeline systems—EGT, MRT, and SESH—are subject to regulation by FERC under the NGA and are considered natural gas companies. Natural gas companies may not charge rates that have been determined to be unjust or unreasonable by FERC. In addition, FERC prohibits natural gas companies from unduly preferring or unreasonably discriminating against any person with respect to pipeline rates or terms and conditions of service. FERC authority over natural gas companies that provide natural gas pipeline transportation services in interstate commerce includes:

- rates, operating terms, conditions of service and service contracts;
- certification and construction of new facilities or expansion of existing facilities;
- extension or abandonment of services and 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 natural gas sales, purchases or transportation; 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 filed 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 costs of providing service, allowed rate of return, volume throughput and contractual capacity commitment assumptions. Our interstate pipelines business 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.

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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 tariff change by making a tariff filing with FERC justifying the proposed tariff change and providing notice, generally 30 days, to the appropriate parties. FERC provides notice to the public through publication of the notice in the Federal Register. If FERC determines that a proposed change is just and reasonable, FERC accepts the proposed change and the pipeline will implement such a change in its tariff, normally 30 days after filing. However, if FERC determines that a proposed change may not be just and reasonable then FERC may suspend such a change for up to five months beyond the date on which the change would otherwise go into effect and set the matter for an administrative hearing. 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 increase is placed into effect before a final FERC determination on such rate increase, and the proposed increase is collected subject to refund (plus interest). Under the second method, FERC may, on its own motion or based on a complaint, 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.

Market Behavior Rules; Posting and Reporting Requirements

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

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

On November 15, 2012, the FERC issued a Notice of Inquiry seeking public comment on the issue of whether to amend its regulations under the natural gas market transparency provisions of Section 23 of the NGA, as adopted by EPAct of 2005, to consider the extent to which quarterly reporting of every natural gas transaction within FERC's NGA jurisdiction that entails physical delivery for the next day or next month would provide useful information for improving natural gas market transparency. On July 9, 2013, the FERC provided notice that it was making a data request of certain natural gas marketers to better assess the reporting requirements. The FERC terminated this Inquiry on November 17, 2015, without taking any further action.

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Intrastate Natural Gas Pipeline and Storage Regulation

Our intrastate natural gas transmission lines are subject to state regulation of rates and terms of service. The scope of such regulation varies state to state. In Oklahoma, our intrastate pipeline system (EOIT) is subject to limited regulation by the Oklahoma Corporation Commission, or 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. In Illinois, our intrastate pipeline system is subject to regulation by the Illinois Commerce Commission.

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

The transportation rates charged by EOIT for natural gas transportation in interstate commerce on intrastate pipelines are subject to the jurisdiction of FERC under Section 311 of the NGPA. EOIT currently has two zones under its Section 311 transportation rate structure—an East Zone and a West Zone. EOIT historically offered only interruptible Section 311 service in both zones. EOIT began to offer firm Section 311 service in the East Zone on April 1, 2009 and in the West Zone on March 1, 2011. 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. EOIT may charge up to its maximum established firm rate for firm Section 311 transportation in its East and West 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.

We also have a pipeline in Illinois that is subject to regulation by the Illinois Commerce Commission as a “Hinshaw pipeline.” Under Section 1(c) of the NGA, a Hinshaw pipeline is exempt from FERC’s NGA regulation if its operations are within a single state, if any gas received from interstate sources is received within the state and if its service is regulated by the state commission. A Hinshaw pipeline may, and our Illinois pipeline does, provide services in interstate commerce pursuant to limited jurisdiction certificate authority under Section 284.224(c) of FERC’s regulations, thereby subjecting itself to the same type of limited FERC jurisdiction imposed on intrastate pipelines engaged in Section 311 service.

In May 2010, FERC issued Order No. 735, which requires intrastate pipelines providing transportation services under Section 311 of the NGPA and Hinshaw pipelines operating under Section 1(c) of the NGA 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 a new 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. Order No. 735 became effective on April 1, 2011. In December 2010, FERC issued Order No. 735-A. In Order No. 735-A, FERC generally reaffirmed Order No. 735 requiring Section 311 and "Hinshaw" pipelines 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

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rates. Our intrastate Stuart Storage Field currently is used exclusively to provide intrastate storage service, even though FERC previously authorized the use of that storage facility for Section 311 interstate service.

Natural Gas Gathering and Processing Regulation

Section 1(b) of the NGA exempts natural gas gathering and processing facilities from the jurisdiction of the FERC. Although the FERC has not made formal determinations with respect to all of our facilities we consider to be gathering facilities, management believes that our natural gas pipelines meet the traditional tests that the FERC has used to determine that a pipeline is a gathering pipeline and is therefore not subject to FERC's NGA jurisdiction. The distinction between FERC-regulated transmission services and federally unregulated gathering services, however, has been the subject of substantial litigation, and the FERC determines whether facilities are gathering facilities on a case-by-case basis, so the classification and regulation of our gathering facilities is subject to change based on future determinations by the FERC, the courts or Congress. If the FERC were to consider the status of an individual facility and determine that the facility and/or services provided by it are not exempt from FERC regulation under the NGA and that the facility provides interstate service, the rates for, and terms and conditions of, services provided by such facility would be subject to regulation by the FERC under the NGA or the NGPA. Such regulation could decrease revenue, increase operating costs, and, depending upon the facility in question, could adversely affect our results of operations and cash flows. In addition, if any of our facilities were found to have provided services or otherwise operated in violation of the NGA or NGPA, this could result in the imposition of civil penalties as well as a requirement to disgorge charges collected for such service in excess of the rate established by the FERC.
States may regulate gathering pipelines. State regulation of gathering facilities generally includes various safety, environmental and, in some circumstances, requirements prohibiting undue discrimination, and in some instances complaint-based rate regulation. Our gathering operations may be subject to ratable take and common purchaser statutes in the states in which they operate. The ratable take statutes generally require gatherers to take, without undue discrimination, natural gas production that may be tendered to the gatherer for handling. Similarly, common purchaser statutes generally require gatherers to purchase without undue discrimination as to source of supply or producer. These statutes are designed to prohibit discrimination in favor of one producer over another producer or one source of supply over another source of supply. These statutes have the effect of restricting our right as an owner of gathering facilities to decide with whom we contract to purchase or transport natural gas.

Oklahoma and Texas have each adopted a form of complaint-based regulation of gathering operations that generally allows natural gas producers and shippers to file complaints with state regulators in an effort to resolve grievances relating to natural gas gathering open access and rate discrimination. Texas has also adopted a complaint based regulation, known as the lost and unaccounted for gas bill, which gives the Texas Railroad Commission the authority to issue orders for purposes of preventing waste in specific situations. To date, neither the gathering regulations nor the lost and unaccounted for gas bill have had a significant impact on our operations in Oklahoma or Texas. However, we cannot predict what effect, if any, either of these regulations might have on our gathering operations in Oklahoma or Texas in the future.

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

Sales of Natural Gas

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

Our sales of natural gas are affected by the availability, terms and cost of pipeline transportation. As noted above, the price and terms of access to pipeline transportation are subject to extensive federal and state regulation. FERC is continually proposing and implementing new rules and regulations affecting those segments of the natural gas industry, most notably interstate natural gas transmission companies that remain subject to FERC jurisdiction. These initiatives also may affect the intrastate transportation of natural gas under certain circumstances. The stated purpose of many of these regulatory changes is to promote competition

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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.

Crude Oil Gathering Regulation

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

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

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

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 pipeline, during which time interested shippers can make commitments to the proposed pipeline project. Throughput commitments from interested shippers during an open season can be for firm service or for non-firm service. Typically, such an open season is for a 30-day period, must be publicly announced, and culminates in interested parties entering into transportation agreements with the carrier. Under FERC precedent, a carrier typically may reserve up to 90% of available capacity for the provision of firm or priority service to shippers making a commitment. At least 10% of capacity ordinarily is reserved for uncommitted shippers, i.e., “walk-up” shippers.

Under the ICA, FERC does not have authority over the siting of oil transportation assets nor over the abandonment of facilities or services. Accordingly, no approval from FERC is necessary prior to placing a new petroleum pipeline project in operation. However, FERC highly encourages carriers to file a Petition for Declaratory Order (PDO) 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.

Safety and Health Regulation

Certain of our facilities are subject to pipeline safety regulations. PHMSA regulates safety requirements in the design, construction, operation and maintenance of jurisdictional natural gas and hazardous liquid pipeline facilities. All natural gas transmission facilities, such as our interstate natural gas pipelines, are subject to PHMSA’s pipeline safety regulations, but natural

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gas gathering pipelines are subject to the pipeline safety regulations only to the extent they are classified as regulated gathering pipelines. In addition, several NGL pipeline facilities and crude oil pipeline facilities are regulated as hazardous liquids pipelines. Currently, each such NGL or crude oil facility is excepted from many of the requirements of PHMSA's regulations applicable to hazardous liquids pipelines based on the facility's location, product transported, and/or the low stress level at which it operates.

Pursuant to the Natural Gas Pipeline Safety Act of 1968, or NGPSA, and the Hazardous Liquid Pipeline Safety Act of 1979, or HLPSA, as amended by the Pipeline Safety Act of 1992, or PSA, the Accountable Pipeline Safety and Partnership Act of 1996, or APSA, the Pipeline Safety Improvement Act of 2002, or PSIA, the Pipeline Inspection, Protection, Enforcement and Safety Act of 2006, or the PIPES Act, and the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011, or the 2011 Pipeline Safety Act, the DOT, through PHMSA, regulates pipeline safety and integrity. The NGPSA regulates safety requirements in the design, construction, operation and maintenance of gas pipeline facilities, while the PSIA establishes mandatory inspections for all U.S. oil and natural gas transmission pipelines in high-consequence areas, or HCAs.

NGL and crude oil pipelines are subject to regulation by PHMSA under the HLPSA which requires PHMSA to develop, prescribe, and enforce minimum federal safety standards for the transportation of hazardous liquids by pipeline, and comparable state statutes with respect to design, installation, testing, construction, operation, replacement and management of pipeline facilities. HLPSA covers petroleum and petroleum products, including NGLs and condensate, and requires any entity that owns or operates pipeline facilities to comply with such regulations, to permit access to and copying of records and to file certain reports and provide information as required by the United States Secretary of Transportation. These regulations include potential fines and penalties for violations. Management believes that we are in compliance in all material respects with these HLPSA regulations. The PSA added the environment to the list of statutory factors that must be considered in establishing safety standards for hazardous liquid pipelines, established safety standards for certain "regulated gathering lines," and mandated that regulations be issued to establish criteria for operators to use in identifying and inspecting pipelines located in HCAs, defined as those areas that are unusually sensitive to environmental damage, that cross a navigable waterway, or that have a high population density. In 1996, Congress enacted the APSA, which limited the operator identification requirement to operators of pipelines that cross a waterway where a substantial likelihood of commercial navigation exists, required that certain areas where a pipeline rupture would likely cause permanent or long-term environmental damage be considered in determining whether an area is unusually sensitive to environmental damage, and mandated that regulations be issued for the qualification and testing of certain pipeline personnel. In the PIPES Act, Congress required mandatory inspections for certain U.S. crude oil and natural gas transmission pipelines in HCAs and mandated that regulations be issued for low-stress hazardous liquid pipelines and pipeline control room management.

PHMSA has developed regulations that require natural gas pipeline operators to implement integrity management programs, including more frequent inspections and other measures to ensure pipeline safety in HCAs. The regulations require operators, including us, to:

- perform ongoing assessments of pipeline integrity;
- identify and characterize applicable threats to pipeline segments that could impact an HCA;
- improve data collection, integration and analysis;
- repair and remediate pipelines as necessary; and
- implement preventive and mitigating actions.

Although many of our pipeline facilities fall within a class that is currently not subject to these integrity management requirements, we may incur significant costs and liabilities associated with repair, remediation, and preventive or mitigating measures associated with our non-exempt pipelines. In 2015, we incurred $32 million of capital expenditures and operating costs for pipeline integrity management. We currently estimate that we will incur capital expenditures and operating costs of up to $290 million from 2016 to 2020 in connection with pipeline integrity management to complete the testing required by existing DOT regulations and their state counterparts. The estimated capital expenditures and operating costs include our estimates for the assessment, remediation and prevention or other mitigation that may be determined to be necessary. At this time, we cannot predict the ultimate costs of our integrity management program and compliance with these regulations because those costs will depend on the number and extent of any repairs found to be necessary and the degree to which newly proposed pipeline safety regulations may apply to our pipeline systems. We will continue to assess, remediate and maintain the integrity of our pipelines. The results of these activities could cause us to incur significant and unanticipated capital and operating expenditures for repairs or upgrades deemed necessary to ensure the continued safe and reliable operations of our pipelines. Additionally, should we fail to comply with DOT or comparable state regulations, we could be subject to penalties and fines. If future DOT pipeline integrity management regulations were to require that we expand our integrity managements program to currently unregulated pipelines, including gathering lines, our costs associated with compliance may have a material effect on our operations.

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The 2011 Pipeline Safety Act reauthorizes funding for federal pipeline safety programs, increases penalties for safety violations, establishes additional safety requirements for newly constructed pipelines, and requires studies of certain safety issues that could result in the adoption of new regulatory requirements for existing pipelines. The 2011 Pipeline Safety Act, among other things, increases the maximum civil penalty for pipeline safety violations and directs the Secretary of Transportation to promulgate rules or standards relating to expanded integrity management requirements, automatic or remote-controlled valve use, excess flow valve use, leak detection system installation and testing to confirm the material strength of pipe operating above 30% of specified minimum yield strength in HCAs. Effective October 25, 2013, PHMSA adopted new rules increasing the maximum administrative civil penalties for violations of the pipeline safety laws and regulations after January 3, 2012 to $0.2 million per violation per day, with a maximum of $2 million for a related series of violations. In 2011, PHMSA issued a final rule applying safety regulations to certain rural low-stress hazardous liquid pipelines that were not covered previously by some of its safety regulations. PHMSA also published advance notice of proposed rulemakings to solicit comments on the need for changes to its natural gas and liquid pipeline safety regulations, including changes to those rules that would apply to gathering lines and removal of an exemption for natural gas pipelines installed before 1970. In May 2012, PHMSA published an advisory bulletin stating that operators of gas and hazardous liquid pipeline facilities should verify records relating to operating specifications for maximum allowable operating pressure, MAOP, for gas pipelines and maximum operating pressure, or MOP, for hazardous liquid pipelines. For natural gas transmission pipelines located within Class 3 and Class 4 locations or in Class 1 and Class 2 locations in HCAs, PHMSA modified its annual report form to require operators to report the number of verified miles of pipeline on their systems. This report was due and filed in June 2013, and subsequently updated in March 2014. No MOP reporting requirements were imposed on operators of hazardous liquid pipeline for the 2012 calendar year reports. Our current practice is to continually monitor and update our records with respect to MAOP of our gas pipelines. Finally, PHMSA has stated that it will propose natural gas pipeline safety standards that are expected to lower methane emissions. Future PHMSA rulemakings and/or industry commitments could have a material impact on our operations.

While we cannot predict the outcome of legislative or regulatory initiatives, such legislative and regulatory changes could have a material effect on our operations, particularly through more stringent and comprehensive safety regulations (such as integrity management requirements) to pipelines and gathering lines not previously subject to such requirements. While we expect any legislative or regulatory changes will provide sufficient time to come into compliance with the new requirements, the costs associated with compliance may have a material effect on our operations.

States are preempted by federal law from imposing pipeline safety standards below the minimum federal standards established by DOT, but they may establish more rigorous standards for intrastate gas and hazardous liquids pipelines. State agencies may also assume responsibility for enforcing intrastate pipeline regulations as a cooperating agency. In practice, states vary considerably in their authority and capacity to address pipeline safety. In the state of Oklahoma, the OCC’s Transportation Division, acting through the Pipeline Safety Department, administers the OCC’s intrastate regulatory program to assure the safe transportation of natural gas, petroleum and other hazardous materials by pipeline. The OCC develops regulations and other approaches to assure safety in design, construction, testing, operation, maintenance and emergency response to pipeline facilities. The OCC derives its authority over intrastate pipeline operations through state statutes and certification agreements with the DOT. A similar regime for safety regulation is in place in Texas and is administered by the Texas Railroad Commission. Our natural gas transmission and DOT regulated gathering pipelines have ongoing inspection and compliance programs designed to keep the facilities in compliance with pipeline safety and pollution control requirements.

We have incorporated all existing requirements into our programs by the required regulatory deadlines, and are continually incorporating the new requirements into procedures and budgets. We expect to incur increasing regulatory compliance costs, based on the intensification of the regulatory environment and forecasted changes to regulations as outlined above. In addition to regulatory changes, costs may be incurred when there is an accidental release of a commodity transported by our system, or a regulatory inspection identifies a deficiency in our required programs.

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. Management believes that we are in material compliance with all applicable laws and regulations relating to worker safety and health.

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The Department of Homeland Security Appropriation Act of 2007 requires the Department of Homeland Security, or DHS, to issue regulations establishing risk-based performance standards for the security of chemical and industrial facilities, including oil and gas facilities that are deemed to present “high levels of security risk.” The DHS issued an interim final rule in April 2007 regarding risk-based performance standards to be attained pursuant to this act and, on November 20, 2007, further issued an Appendix A to the interim rules that establish chemicals of interest and their respective threshold quantities that will trigger compliance with these interim rules. Covered facilities that are determined by DHS to pose a high level of security risk will be required to prepare and submit Security Vulnerability Assessments and Site Security Plans as well as comply with other regulatory requirements, including those regarding inspections, audits, recordkeeping, and protection of chemical-terrorism vulnerability information.

While we are not currently subject to governmental standards for the protection of computer-based systems and technology from cyber threats and attacks, proposals to establish such standards are being considered by the U.S. Congress and by U.S. Executive Branch departments and agencies, including the Department of Homeland Security, and we may become subject to such standards in the future. We have systems in place to monitor and address the risk of cyber-security breaches in our business, operations and control environments. We routinely review and update those systems as the nature of that risk requires. We are not aware of any cyber-security breach affecting any of our business, operations or control environments. A significant cyber-attack could have a material effect on our operations and those of our customers.

Environmental Matters

General

Our activities are subject to stringent and complex federal, state and local laws and regulations governing environmental protection including the discharge of materials into the environment. 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 our wastes, requiring remedial action to mitigate pollution conditions that may be caused by our operations or that are attributable to former operations, regulating future construction activities to mitigate harm to threatened or endangered species, wetlands and migratory birds, and requiring the installation and operation of pollution control equipment. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, the imposition of remedial requirements and the issuance of orders enjoining future operations. Management believes that our operations are in material compliance with current federal, state and local environmental standards.

Environmental regulation can increase the cost of planning, design, initial installation and operation of our facilities and has the potential to restrict or delay our operations and development projects, particularly pipeline projects. Historically, our total expenditures for environmental control measures and for remediation have not been significant in relation to our consolidated financial position or results of operations. Management believes, however, that it is reasonably likely that the trend in environmental legislation and regulations will continue towards more restrictive standards. Compliance with these standards is expected to increase the cost of conducting business.

Our routine environmental expenses for 2015 for technical support, fees, sampling, testing and other similar items were approximately $6 million. Reciprocating internal combustion engines maximum achievable control technology (RICE MACT) and greenhouse gases (GHG) expenses for 2015 were approximately $2 million. Routine expenses for 2016 to 2018 are expected to average $7 million per year, and RICE MACT and GHG costs are expected to average $2 million per year over the same timeframe. Costs for incidental environmental activities, such as permitting as part capital projects and waste disposal, are included in routine capital and operating expenses. Management continues to evaluate our compliance with existing and proposed environmental regulations and implements appropriate environmental programs in a competitive market.

Air

Our operations are subject to the federal Clean Air Act, as amended (CAA), 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 also 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. 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.

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Climate Change

More stringent laws and regulations relating to climate change and GHGs (including methane) may be adopted in the future and could cause us to incur material expenses in complying with them. The United States Congress has, from time to time, considered adopting legislation to reduce emissions of GHGs, and there has been a wide-ranging policy debate, both nationally and internationally, regarding the impact of these gases and possible means for their regulation. Some of the proposals would require industrial sources to meet stringent new standards that would require substantial reductions in GHG emissions. Please read Item 1A, “Risk Factors - Risks Related to Our Business - Our operations may incur substantial liabilities to comply with climate change legislation and regulatory initiatives.” for more information. Following a finding by the U.S. Environmental Protection Agency (EPA) that certain GHGs represent an endangerment to human health, the EPA adopted two sets of rules regulating GHG emissions under the Clean Air Act. One requires a reduction in emissions of GHGs from motor vehicles beginning January 2, 2011. The other regulates emissions of GHGs from certain large stationary sources under the Clean Air Act's Prevention of Significant Deterioration and Title V programs, commencing when the motor vehicle standards took effect on January 2, 2011. Also, the EPA adopted its “Mandatory Reporting of Greenhouse Gases Rule” that requires the annual calculation and reporting of GHG emissions from natural gas transmission, gathering, processing and distribution systems and electric distribution systems that emit 25,000 metric tons or more of carbon dioxide equivalent (CO_{2e}) per year. These additional reporting requirements began in 2012 and we are currently in compliance. These permitting and reporting requirements could lead to further regulation of GHGs by the EPA.

Although the adoption of new legislation is uncertain, action by the EPA to impose new standards and reporting requirements regarding GHG emissions continues. For example, on September 19, 2015, the EPA announced a proposed rule setting standards for methane and VOC emissions from new and modified oil and gas production sources and natural gas processing and transmission sources. The rule is expected to be final sometime in mid-2016. Similarly, in January 2016, the Bureau of Land Management proposed rules to require additional efforts by producers to reduce venting, flaring, and leaking of natural gas produced on federal and Native American lands. Furthermore, in October 2015, the EPA finalized proposed changes to its GHG reporting rule that requires additional reporting from natural gas transmission pipelines as well as gathering and boosting stations. This rule was effective January 1, 2016.

Several states have passed laws, adopted regulations or undertaken regulatory initiatives to reduce the emission of GHGs, primarily through the planned development of GHG emission inventories and/or regional GHG cap and trade programs. Oklahoma, Arkansas, Louisiana, Kansas, Missouri, Illinois, Tennessee, Mississippi, Alabama, North Dakota and Texas are not among them. If legislation or regulations are passed at the federal or state levels in the future requiring mandatory reductions of carbon dioxide, methane and other GHGs on our facilities, this could result in significant additional compliance costs that would affect the our future financial position, results of operations and cash flows.

The adoption of legislation or regulatory programs to reduce emissions of GHGs , including methane, could require us to incur increased operating costs, such as costs to purchase and operate emissions monitoring and control systems, to acquire emissions allowances or comply with new regulatory or reporting requirements. Any such legislation or regulatory programs could also increase the cost of consuming, and thereby reduce demand for, the natural gas we gather, treat and transport. Consequently, legislation and regulatory programs to reduce emissions of GHGs could have an adverse effect on our business, financial condition and results of operations.

National Environmental Policy Act (NEPA)

NEPA provides for regulatory review in connection with certain projects that involve federal lands or require certain actions by federal agencies, which implicates a number of other laws and regulations such as the Endangered Species

Act (ESA), 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. Some of our projects that require NEPA review are related to pipeline integrity. Ineffective implementation of this process could cause significant impacts to commercial and compliance projects.

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

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restricted or delayed, or we could be required to implement expensive mitigation measures. Moreover, as a result of a settlement approved by the U.S. District Court for the District of Columbia in September 2011, the U.S. Fish and Wildlife Service is required to make a determination on listing of more than 250 species as endangered or threatened under the ESA by no later than completion of the agency’s 2017 fiscal year. The designation of previously unprotected species as threatened or endangered in areas where underlying property operations are conducted could cause us to incur increased costs arising from species protection measures or could result in limitations on our customer’s exploration and production activities that could have an adverse impact on demand for our services. Portions of the basins we serve are designated as critical or suitable habitat for threatened and endangered species. If additional portions of the basins we serve were designated as critical or suitable habitat for threatened and endangered species, it could adversely impact the cost of operating our systems and of constructing new facilities. Management believes that we are in material compliance with all applicable laws providing special protection to designated species.

Hazardous Substances and Waste

Our operations are subject to federal and state environmental laws and regulations relating to the management and release of hazardous substances, solid and hazardous wastes, and petroleum hydrocarbons. For instance, our operations are subject to the Comprehensive Environmental Response, Compensation and Liability Act of 1980 (CERCLA or Superfund) 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 be subject to joint and several 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. At this time, it is not anticipated that any associated liability will cause a significant impact to us.

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. Further, these RCRA-exempt oil and gas exploration and production wastes may still be regulated under state law or RCRA’s less stringent solid waste requirements. The transportation of natural gas in pipelines may also generate some hazardous wastes that are subject to RCRA or a comparable state law regime.

Water

Our operations are subject to the federal Clean Water Act 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 federal Clean Water Act 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 federal Clean Water Act and regulations implemented thereunder also prohibit discharges of dredged and fill material in wetlands and other waters of the United States unless authorized by an appropriately issued permit. 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.

The primary federal law related to oil spill liability is the Oil Pollution Act (the OPA) which amends and augments oil spill provisions of the Clean Water Act and imposes certain duties and liabilities on certain “responsible parties” related to the prevention of oil spills and damages resulting from such spills in or threatening United States waters or adjoining shorelines. A liable “responsible party” includes the owner or operator of a facility, vessel or pipeline that is a source of an oil discharge or that poses the substantial threat of discharge, or in the case of offshore facilities, the lessee or permittee of the area in which a discharging facility is located. OPA assigns joint and several liability, without regard to fault, to each liable party for oil removal costs and a

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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 oil and gas commission. A number of federal agencies, including the EPA and the U.S. Department of Energy, are analyzing, or have been requested to review, a variety of environmental issues associated with hydraulic fracturing. 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. If new laws or regulations that significantly restrict hydraulic fracturing are adopted, such laws could make it more difficult or costly for our customers to perform fracturing to stimulate production from tight formations. Restrictions on hydraulic fracturing could also reduce the volume of natural gas that our customers produce, and could thereby adversely affect our revenues and results of operations.

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

Impact of Seasonality

While the results of our gathering and processing segment are not materially affected by seasonality, from time to time our operations can be impacted by inclement weather. Our transportation and storage segment experiences seasonal impacts associated with storage spreads, basis spreads on market-based pipelines, power plant demand and local distribution company customer demand.

Employees

As of December 31, 2015, we employ approximately 1,640 employees with an additional 166 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 Party Transactions—Employee Agreements" 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, and securities markets generally. If any of the following risks were actually to occur, our business, financial condition 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 pay the minimum quarterly distribution to holders of our common and subordinated units.

We may not have sufficient available cash each quarter to enable us to pay the minimum quarterly distribution. 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 midstream energy companies;
- 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; and
- other business risks affecting our cash levels.

Our contracts are subject to renewal risks.

We generate a substantial portion of our gross margins under long-term, fee-based agreements. For the year ended December 31, 2015, approximately 81% of our gross margin was generated from contracts that are fee-based and approximately 56% of our gross margin was attributable to fees associated with firm contracts or contracts with minimum volume commitment features. As these and other contracts expire, we may have to negotiate extensions or renewals with existing suppliers and customers or enter into new contracts with other suppliers and customers. We may be unable to obtain new contracts on favorable commercial terms, if at all. We also may be unable to maintain the economic structure of a particular contract with an existing customer or the overall mix of our contract portfolio. For example, depending on prevailing market conditions at the time of a contract renewal, gathering and processing customers with fixed-fee or fixed-margin contracts may desire to enter into contracts under different fee arrangements. To the extent we are unable to renew our existing contracts on terms that are favorable to us, if at all, or successfully manage our overall contract mix over time, our revenue, results of operations and distributable cash flow could be adversely affected.

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

We provide firm transportation and storage services to certain key customers on our system. Our major transportation customers are affiliates of CenterPoint Energy, Laclede, AEP, XTO and OGE Energy.

The loss of all or even a portion of the interstate or intrastate transportation and storage services for any of these customers, the failure to extend or replace these contracts or the extension or replacement of these contracts on less favorable terms, as a result of competition or otherwise, could adversely affect our financial position, results of operations and our 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 continued availability of natural gas, NGL and crude oil production. We have no control over the level of drilling activity in our areas of operation, the amount of reserves associated with wells connected to our systems or the rate at which production from a well declines. In addition, our cash flows associated with wells currently connected to our systems will decline over time. 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 and crude oil

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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 these systems, our ability to compete for volumes from successful new wells and our ability to expand 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 have a material adverse effect on our results of operations and distributable cash flow. 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 and the regulation of hydraulic fracturing; and
- the availability of drilling rigs and other costs of production and equipment.

Fluctuations in energy prices can also greatly affect the development of new natural gas and crude oil reserves. Drilling and production activity generally decreases as commodity prices decrease. In general terms, the prices of natural gas, 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 factors, even if new natural gas or crude oil 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. Over the course of 2015 and continuing into 2016, natural gas and crude oil prices have dropped to their lowest levels in over 10 years from a high of $13.31 per MMBtu in July 2008 to $1.63 MMBtu at December 23, 2015 and $145.31 per barrel in July 2008 to $26.19 per barrel at February 11, 2016, respectively. A sustained decline 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 have a material adverse effect on our business, financial position, results of operations and ability to make quarterly cash distributions to our 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. In addition to capital expenditures to support growth, the steeper production decline curves associated with unconventional resource plays may require us to incur higher maintenance capital expenditures relative to throughput over time, which will reduce our distributable cash flow.

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. Reductions in drilling activity would result in our inability to maintain the current levels of throughput on our systems and could have a material adverse effect on our financial position, results of operations and distributable cash flow.

Our industry is highly competitive, and increased competitive pressure could adversely affect our financial position, results of operations and distributable cash flow.

We compete with similar enterprises in our respective areas of operation. The principal elements of competition are rates, terms of service and flexibility and reliability of service. Our competitors include large crude oil, natural gas and petrochemical 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

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natural gas could lead to a reduction in demand for natural gas gathering, processing, transportation and transportation services. All of these competitive pressures could adversely affect our results of operations and distributable cash flow.

We derive a substantial portion of our operating income and cash flow from subsidiaries through which we hold a substantial portion of our assets.

We derive a substantial portion of our operating income and cash flow 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 holders of our common and subordinated units 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 flows and not solely on profitability, which will be affected by non-cash items. 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, 2016, we estimate that expansion capital will be approximately $375 million and our maintenance capital could range from approximately $105 million to $125 million. For example, we are currently constructing two cryogenic processing facilities that we plan to connect to our super-header system in Grady and Garvin County, Oklahoma, which are expected to add 400 MMcf/d of combined natural gas processing capacity. The first of the two new plants (the Bradley II Plant) is expected to be completed in the second quarter of 2016. The second plant (the Wildhorse Plant) is a 200 MMcf/d plant that is expected to be completed in late 2017. We also plan to construct natural gas gathering and compression infrastructure to support producer activity.

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 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 results of operations and our 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 due to numerous uncertainties inherent in estimating future production. As a result, new facilities may not be able to attract sufficient throughput to achieve expected investment return, which could adversely affect our results of operations and our ability to make cash distributions to unitholders.

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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 results of operations and our 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 results of operations and our ability to make cash distributions to unitholders could be negatively affected by adverse movements 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. Over the course of 2015 and continuing into 2016, natural gas and crude oil prices have dropped to their lowest levels in over 10 years from a high of $13.31 per MMBtu in July 2008 to $1.63 MMBtu at December 23, 2015 and $145.31 per barrel in July 2008 to $26.19 per barrel at February 11, 2016, respectively.

Our keep-whole natural gas processing arrangements, which accounted for 5% of our natural gas processed volumes in 2015, expose us to fluctuations in the pricing spreads between NGL prices and natural gas prices. Under these arrangements, the processor processes raw natural gas to extract NGLs and redelivers to the producer the natural gas equivalent Btu value of raw natural gas received from the producer in the form of processed natural gas. The processor retains the processed NGLs and to sell them for its own account. Accordingly, the processor’s cost of natural gas and natural gas liquids is a function of the difference between the value of the NGLs produced and the cost of the processed natural gas used to replace the natural gas equivalent Btu value of those NGLs. Therefore, if natural gas prices increase and NGL prices do not increase by a corresponding amount, the processor has to replace the Btu of natural gas at higher prices and cost of natural gas and natural gas liquids sold are negatively affected.

Our percent-of-proceeds and percent-of-liquids natural gas processing agreements accounted for 47% of our natural gas processed volumes in 2015. Under percent-of-proceeds processing arrangements, the processor generally purchases unprocessed natural gas from the producer for a purchase price that is based on published natural gas and NGL index prices. The purchase price for unprocessed natural gas is calculated based on a percentage of the quantity of natural gas and NGLs that would result from processing the gas purchased. Accordingly, the processor’s cost of goods sold is a percentage of the index price value of the natural gas and NGLs contained in the unprocessed natural gas. If we are unable to sell the processed natural gas and NGLs at a higher price than we pay, our margins from sale of goods is negatively affected. Additionally, if the amount of processed natural gas or NGLs recovered during processing is less than the amount upon which the purchase price was based, our margins from sale of goods may be negatively affected.

Under percent-of-liquids processing arrangement, the processor generally purchases the NGLs in unprocessed natural gas received from the producer, processes the natural gas, and returns the processed natural gas to the producer. The purchase price for NGLs is based on published NGL index prices and is calculated based on a percentage of the quantity of NGLs that would result from processing the gas. Accordingly, the processor’s cost of goods sold is a percentage of the index price value of NGLs contained in the unprocessed natural gas. If we are unable to sell the NGLs recovered during processing at a higher price than we pay, our margins from sale of goods is negatively affected. Additionally, if the amount of NGLs recovered during processing is less than the amount upon which the purchase price was based, our margins from sale of goods may be negatively affected.

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

We have limited experience in the crude oil gathering business.

In November 2013, we commenced operations on our initial crude oil gathering pipeline system, located in Dunn and McKenzie Counties in North Dakota within the Bakken Shale formation. Additionally in February 2014, we executed a crude oil gathering agreement to gather crude oil production through a new system in Williams and Mountrail Counties in North Dakota that commenced operations in the second quarter of 2015. These facilities, which will have a combined capacity of 49,500 barrels per day, are the first crude oil gathering systems that we have built and operated. Other operators of gathering systems in the

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Bakken Shale formation may have more experience in the construction, operation and maintenance of crude oil gathering systems than we do. This relative lack of experience may hinder our ability to fully implement our business plan in a timely and cost efficient manner, which, in turn, may adversely affect our results of operations and our ability to make cash distributions to unitholders.

We are exposed to credit risks of our customers, and any material nonpayment or nonperformance by our key customers could adversely affect our cash flow and results of operations.

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

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

As of December 31, 2015, approximately 60% of our contracted transportation firm capacity and 44% of our contracted storage firm capacity was subscribed under such "negotiated rate" contracts. These contracts generally do not include provisions allowing for adjustment for increased costs due to inflation, pipeline safety activities or other factors that are not tied to an applicable tracking mechanism authorized by FERC. Successful recovery of any shortfall of revenue, representing the difference between "recourse rates" (if higher) and negotiated rates, is not assured under current FERC policies.

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

We depend upon third-party natural gas pipelines to deliver natural gas to, and take natural gas from, our transportation systems. We also depend on third-party facilities to transport and fractionate NGLs that are delivered to the third party at the tailgates of the processing plants. Fractionation is the separation of the heterogeneous mixture of extracted NGLs into individual components for end-use sale. For example, an outage or disruption on certain pipelines or fractionators operated by a third party could result in the shutdown of certain of 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 results of operations and our 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 on land owned by third parties and governmental agencies for a specific period of time. 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 results of operations and our ability to make cash distributions to unitholders.

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We conduct a portion of our operations through joint ventures, which subject us to additional risks that could have a material adverse effect on the success of these operations, our financial position and our results of operations.

We conduct a portion of our operations through joint ventures with third parties, including Spectra Energy Partners, LP, DCP Midstream Partners, LP, Trans Louisiana Gas Pipeline, Inc. and Pablo Gathering LLC. We may also enter into other joint venture arrangements in the future. These third parties may have obligations that are important to the success of the joint venture, such as the obligation to pay their share of capital and other costs of the joint venture. The performance of these third-party obligations, including the ability of the third parties to satisfy their obligations under these arrangements, is outside our control. If these parties do not satisfy their obligations under these arrangements, our business may be adversely affected.

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

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

The risks described above or the failure to continue our joint ventures or to resolve disagreements with our joint venture partners could adversely affect our ability to transact the business that is the subject of such joint venture, which would in turn negatively affect our financial condition, results of operations and distributable cash flows. 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, Spectra Energy Partners, LP 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 Spectra Energy Partners, LP. CenterPoint Energy owns a 55.4% limited partner interest in us 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 limited partner interest in us and its economic interest in our general partner, or does not have the ability to exercise certain control rights, Spectra Energy Partners, LP could have the right to purchase our interest in SESH at fair market value.

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

In connection with acquisitions, we may record goodwill and identifiable intangible assets. Goodwill is recorded when the purchase price of a business exceeds the fair market value of the tangible and separately measurable intangible net assets. GAAP requires us to test goodwill and intangible assets with indefinite useful lives for impairment on an annual basis or when events or circumstances occur indicating that goodwill might be impaired. Long-lived assets, including intangible assets with finite useful lives, are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount may not be recoverable. We recorded impairments to long-lived assets, including intangible assets with finite useful lives, of $47 million during the year ended December 31, 2015. For the investments we account for under the equity method, the impairment test considers whether the fair value of the equity investment as a whole, not the underlying net assets, has declined and whether that decline is other than temporary. If we determine that an impairment is indicated, we would be required to take an immediate non-cash charge to earnings with a correlative effect on equity and balance sheet leverage as measured by debt to total capitalization. We recorded impairments to goodwill of $1,087 million during the year ended December 31, 2015. Although as a result of these impairments we had no goodwill recorded as of December 31, 2015, we could experience future events that result in impairments if goodwill is recorded as a result of future acquisitions. An impairment of goodwill, long-lived assets, including intangible assets, or equity method investments could have a significant negative impact on our future operating results and could have an adverse impact on 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 impact our 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 and other natural disasters, acts of terrorism and actions by third parties;
- inadvertent damage from construction, vehicles, farm and utility equipment;
- leaks of natural gas, 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 and/or loss of life, severe damage to and destruction of property, plant and equipment and pollution or other environmental damage. These risks may also result in curtailment or suspension of our operations. A natural disaster or other hazard affecting the areas in which we operate could have a material adverse effect on our 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 negative impact on our 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 negatively impact our 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.

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

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.

Our ability to grow is dependent on our ability to access external financing sources.

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 primarily upon external financing sources, including commercial bank borrowings and the issuance of debt and equity securities, to fund acquisitions and expansion capital expenditures. As a result, to the extent we or our operating subsidiaries are unable to finance growth externally, our and our operating subsidiaries' cash distribution policy will 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.

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 on access to the capital markets to fund our expansion capital expenditures. Historically, unit prices of midstream master limited partnerships have experienced periods of volatility. In addition, because our common units are yield-based securities, rising market interest rates could impact the relative attractiveness of our common units to investors. 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.

Further, the Private Placement, which is expected to close prior to the end of the first quarter of 2016, is subject to the completion of due diligence by CenterPoint Energy, including the review of our audited financial statements and this Form 10-K, and certain customary closing conditions. If these conditions are not satisfied or waived, the Private Placement may not be consummated prior to the end of the first quarter of 2016 or at all.

If we do not make acquisitions or are unable to make acquisitions on economically acceptable terms, our future growth will be adversely affected.

Our growth strategy includes, in part, the ability to make acquisitions that result in an increase in our cash generated from operations. If we are unable to make these accretive acquisitions either because: (i) we are unable to identify attractive acquisition targets or we are unable to negotiate purchase contracts on acceptable terms, (ii) we are unable to obtain acquisition financing on economically acceptable terms, or (iii) we are outbid by competitors, then our future growth and ability to increase distributions will be adversely affected.

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

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.

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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, 2015, we had approximately $2.7 billion of long-term debt outstanding, excluding the premiums on senior notes, and $363 million of long-term notes payable—affiliated companies due to CenterPoint Energy. In addition,we had$236 million outstanding under our commercial paper program as of December 31, 2015. We have a $1.75 billion Revolving Credit Facility for working capital, capital expenditures and other partnership purposes, including acquisitions, of which $1.2 billion was available as of December 31, 2015. 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 business, financial condition, results of operations and ability to make quarterly 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, CenterPoint Energy, OGE Energy and their affiliates have agreed to hold or otherwise conduct all of their respective midstream operations located within the United States through us. This requirement will cease to apply to both CenterPoint Energy and OGE Energy as soon as either CenterPoint Energy or OGE Energy ceases to hold any interest in our

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general partner or at least 20% of our common units. In addition, if CenterPoint Energy or OGE Energy acquires any assets or equity of any person engaged in midstream operations with a value in excess of $50 million (or $100 million in the aggregate with such party's other acquired midstream operations that have not been offered to us), the acquiring party will be required to offer to us such assets or equity 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 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.

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

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

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 cash flows.

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 Indian lands. Certain approval procedures may require preparation of archaeological surveys, endangered species studies and other studies to assess the environmental impact of new sites or the expansion of existing sites. Compliance with these regulatory requirements is expensive and significantly lengthens the time required to prepare applications and to receive authorizations.

Costs of compliance with existing environmental laws and regulations are significant, and the cost of compliance with future environmental laws and regulations may adversely affect our results of operations and our 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. There are significant capital, operating and other costs associated with compliance with these environmental statutes, rules and regulations and those costs may be even more significant in the future.

There is inherent risk of the incurrence of environmental costs and liabilities in our operations due to our handling of natural gas, NGLs, crude oil, produced water and air emissions related to our operations and historical industry operations and waste disposal practices. These activities are subject to stringent and complex federal, state and local laws and regulations 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 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 could result in reductions or delays in natural gas production by our customers, which could adversely affect our results of operations and our ability to make cash distributions to unitholders.

Hydraulic fracturing is common practice that is used by many of our customers to stimulate production of natural gas and/or oil from dense subsurface rock formations. The hydraulic fracturing process involves the injection of water, sand, and chemicals under pressure into targeted subsurface formations to fracture the surrounding rock and stimulate production. Many of our customers commonly use hydraulic fracturing techniques in their drilling and completion programs. Hydraulic fracturing typically is regulated by state oil and natural gas commissions. In addition, certain federal agencies have proposed additional laws and regulations to more closely regulate the hydraulic fracturing process. For example, in September 2015, the EPA published proposed updates to new source performance standard requirements that would impose more stringent controls on methane and volatile organic compounds emissions from oil and gas development and production operations, including hydraulic fracturing and other well completion activity. Congress from time to time has considered the adoption of legislation to provide for federal regulation of hydraulic fracturing under the Safe Drinking Water Act (SDWA) and to require disclosure of the chemicals used in the hydraulic fracturing process. Some states have adopted, and other states are considering adopting, legal requirements that could impose more stringent permitting, public disclosure or well construction requirements on hydraulic fracturing activities. Local government also may seek to adopt ordinances within their jurisdictions regulating the time, place and manner of drilling activities in general or hydraulic fracturing activities in particular, in some cases banning hydraulic fracturing 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.

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In addition, certain governmental reviews have been conducted or are underway that focus on environmental aspects of hydraulic fracturing practices. The U.S. Environmental Protection Agency, or the EPA, has commenced a study of the potential environmental effects of hydraulic fracturing on drinking water and groundwater. A draft report was released in June 2015, which concluded that hydraulic fracturing activities have not led to widespread, systemic impacts on drinking water resources in the United States, although there may be above and below ground mechanisms by which hydraulic fracturing activities have the potential to impact drinking water resources. The draft report is expected to be finalized after a public comment period and a formal review by the EPA’s Science Advisory Board. The White House Council on Environmental Quality is also coordinating an administration-wide review of hydraulic fracturing practices. Other governmental agencies, including the U.S. Department of Energy, have evaluated or are evaluating various other aspects of hydraulic fracturing. These ongoing or proposed studies, depending on their degree of pursuit and any meaningful results obtained, could spur initiatives to further regulate hydraulic fracturing under the SDWA or other regulatory mechanisms.

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

Because our operations emit various types of greenhouse gases, legislation and regulations governing greenhouse gas emissions could increase our costs related to operating and maintaining our facilities, and could delay future permitting. At the federal level, the EPA has adopted regulations under existing provisions of the federal Clean Air Act that, among other things, require the monitoring and reporting of GHG emissions from specified onshore and offshore oil and natural gas production sources in the United States on an annual basis, which include certain of our operations. Additional rules, such as the updates to the oil and gas new source performance standard requirements proposed by the EPA in September 2015 or the additional requirements related to natural gas production on federal lands proposed by the Bureau of Land Management in January 2016, could affect our ability to obtain air permits for new or modified facilities or require our operations to incur additional expenses to control air emissions by installing emissions control technologies and adhering to a variety of work practice and other requirements. These requirements could increase the costs of development and production, reducing the profits available to us and potentially impairing our operator’s ability to economically develop our properties.

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

Increased regulatory-imposed costs may increase the cost of consuming, and thereby reduce demand for, the products that we gather, treat and transport. To the extent financial markets view climate change and emissions of greenhouse gases as a financial risk, this view could negatively affect our ability to access capital markets or cause us to receive less favorable terms and conditions. Consequently, legislation and regulatory initiatives aimed at reducing greenhouse gases could have a material adverse effect on our results of operations and our ability to make cash distributions to unitholders.

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

Our operations are subject to extensive regulation by federal regulatory authorities. Changes or additional regulatory measures adopted by such authorities could have a material adverse effect on our results of operations and our 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

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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 condition, results of operations and cash flows and our 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 the 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 EPACT 2005, FERC has civil penalty authority under the NGA and the NGPA to impose penalties for current violations of up to $1 million per day for each violation and possible criminal penalties of up to $1 million per violation.

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

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

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

Our crude oil gathering pipelines 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 requires, among other things, that our rates must

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be “just and reasonable” and that we provide service in a manner that is nondiscriminatory. Shippers on our crude oil gathering pipelines may protest our tariff filings, file complaints against our existing rates, or FERC can investigate our rates on its own initiative. In the event that 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 results of operations and our 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. The relevant states in which we operate include North Dakota, Oklahoma, Arkansas, Louisiana, Texas, Missouri, Kansas, Mississippi, Tennessee and Illinois. State and local regulations generally focus on safety, environmental and, in some circumstances, prohibition of undue discrimination among shippers. Additional rules and legislation pertaining to these matters are considered and, in some instances, adopted from time to time. 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 distributable cash flow.

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

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

A change in the jurisdictional characterization of some of 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 operations are generally exempt from the jurisdiction of FERC under the NGA, but 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 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 gathering pipeline and are therefore not subject to FERC jurisdiction. The distinction between FERC-regulated transmission services and federally unregulated gathering services, however, has been the subject of substantial litigation, and FERC determines whether facilities are gathering facilities on a case-by-case basis, so the classification and regulation of our gathering facilities is subject to change based on future determinations by 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 financial condition, results of operations and cash flows and our 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 or NGPA, 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.

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Natural gas gathering may receive greater regulatory scrutiny at the state level; therefore, our natural gas gathering 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 pipeline integrity and other similar programs and related repairs.

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

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

Although many of our pipelines fall within a class that is currently not subject to these requirements, we may incur significant cost and liabilities associated with repair, remediation, preventive or mitigation measures associated with our non-exempt pipelines. This work is part of our normal integrity management program and we do not expect to incur any extraordinary costs during 2016 to complete the testing required by existing DOT regulations and their state counterparts. We have not estimated the costs for any repair, remediation, preventive or mitigation actions that may be determined to be necessary as a result of the testing program, which could be substantial, or any lost cash flows resulting from shutting down our pipelines during the pendency of such repairs. Should we fail to comply with DOT or comparable state regulations, we could be subject to penalties and fines. Also, the scope of the integrity management program and other related pipeline safety programs could be expanded in the future. We have not estimated the cost of complying with such future requirements. Such future requirements could adversely affect our financial position, results of operations and our ability to make cash distributions to unitholders.

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

Under final rules adopted by the CFTC, management believes our hedging transactions will qualify for the non-financial, commercial end-user exception, which exempts derivatives intended to hedge or mitigate commercial risk from the mandatory swap clearing requirement, where the counterparty such as us has a required identification number, is not a financial entity as defined by the regulations, and meets a minimum asset test. The Dodd-Frank Act may also require 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

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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 officers and directors of our general partner. Some of the directors of our general partner are also directors of CenterPoint Energy or OGE Energy. Although our general partner has a duty to manage us in a manner that is beneficial to us and our unitholders, the directors and officers of our general partner have a fiduciary duty to manage our general partner in a manner that is beneficial to CenterPoint Energy and OGE Energy. 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 our 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.
- 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 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 and OGE Energy.
- Our 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 and the ability of the subordinated units to convert to common units.

- 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 a distribution on the subordinated units, to make incentive distributions or to accelerate the expiration of the subordination period.
- Our 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

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may be used to fund distributions on our subordinated or general partner units or to our general partner in respect of the incentive distribution rights.

- Our partnership agreement does not restrict 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 subordinated 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.

In addition, because we intend 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 facilities 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.

The reimbursements due to our general partner and its affiliates for services provided to us or on our behalf will reduce our distributable cash flow. The amount and timing of such reimbursements will be determined by our general partner.

Prior to making any distribution on our common units, we will reimburse our general partner and its affiliates, including CenterPoint Energy and OGE Energy, for costs and expenses they incur and payments they make on our behalf. Pursuant to services agreements we have entered into with each of CenterPoint Energy and OGE Energy, we will reimburse CenterPoint Energy and OGE Energy for the payment of operating expenses related to our operations and for the provision of various general and administrative services performed for our benefit. Payments for these services may be substantial and will reduce the amount of distributable cash flow. Additionally, we will reimburse CenterPoint Energy and OGE Energy for direct or allocated costs and expenses incurred on our behalf, including administrative costs, such as compensation expense for those persons who provide services necessary to run our business, and insurance expenses. Our partnership agreement provides that our general partner will determine in good faith the expenses that are allocable to us. The reimbursement of expenses and payment of fees, if any, to our general partner and its affiliates will reduce the amount of available cash to pay cash distributions to our common 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. On February 2, 2016, Standard & Poor's Ratings Services lowered its credit rating of the Partnership from an investment grade rating to a non-investment grade rating. As a result, we expect our access to the commercial paper markets to be limited. If either Moody’s Investors Service or Fitch Ratings lowers its credit ratings of the Partnership from an investment grade rating to a non-investment grade rating while our rating from Standard & Poor’s Ratings Services is below investment grade, or if both Moody’s Investors Service and Fitch Ratings lower their credit ratings of the Partnership from an investment grade rating to a non-investment rating, the cost of our borrowings will increase. So long as 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 our ability to make cash distributions to unitholders could be adversely affected.

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

The credit and business risk profiles and the business plans of our sponsors, CenterPoint Energy and OGE Energy, 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 more risky 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.

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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 subbullets 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, at any time when there are no subordinated units outstanding, 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.

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

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

The unitholders are unable to remove our general partner without its consent because affiliates of our general partner own sufficient units to be able to prevent its removal. The vote of the holders of at least 75% of all outstanding units voting together as a single class is required to remove our general partner. As of February 1, 2016, affiliates of our general partner owned 81.7% of our aggregate outstanding common and subordinated units. Also, if our general partner is removed without cause during the subordination period and units held by our general partner and its affiliates are not voted in favor of that removal, all remaining subordinated units will automatically convert into common units and any existing arrearages on our common units will be extinguished. A removal of our general partner under these circumstances would adversely affect our common units by prematurely eliminating their distribution and liquidation preference over our subordinated units, which would otherwise have continued until we had met certain distribution and performance tests. "Cause" is narrowly defined under our partnership agreement to mean that a court of competent jurisdiction has entered a final, non-appealable judgment finding our general partner liable for actual fraud or willful misconduct in its capacity as our general partner. "Cause" does not include most cases of charges of poor management of the business, so the removal of our general partner because of the unitholders' dissatisfaction with our general partner's performance in managing us will most likely result in the termination of the subordination period and conversion of all subordinated units to 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. Although the limited liability company agreement of our general partner restricts the ability of CenterPoint Energy and OGE Energy to transfer their ownership of their respective limited liability company interest in our general partner until May 1, 2016, 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 executive officers of our general partner with its own choices and thereby influence the decisions taken by the Board of Directors and executive 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. For example, a transfer of incentive distribution rights by our general partner could reduce the likelihood of CenterPoint Energy or OGE Energy selling or contributing additional assets to us, as they would have less of an economic incentive to grow our business, which in turn would impact our ability to grow our asset base.

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

Our 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 a lower percentage of total outstanding units will be subordinated units, the risk that a shortfall in the payment of the minimum quarterly distribution will be borne by our common unitholders will increase;
- 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.

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.

As of February 1, 2016, subsidiaries of CenterPoint Energy and OGE Energy hold an aggregate of 136,983,998 common units and 207,855,430 subordinated units. All of the subordinated units will convert into common units at the end of the subordination period and some may convert earlier under certain circumstances. In addition, we have agreed to provide CenterPoint Energy, OGE Energy and ArcLight with 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.

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 the common units, our general partner will have the right, which it may assign to any of its affiliates or to us, but not the obligation, to acquire all, but not less than all, of the common units held by unaffiliated persons at a price not less than their then-current market price, as calculated pursuant to the terms of the partnership agreement. If our general partner and its affiliates reduce their ownership percentage to below 70% of the outstanding units, the ownership threshold to exercise the call right will be permanently reduced to 80%. As a result, our unitholders may be required to sell their common units at an undesirable time or price and may not receive any positive return on their investment. Our unitholders may also incur a tax liability upon any such sale of their units. As of February 1, 2016, affiliates of our general partner owned approximately 63.9% of our outstanding common units. At the end of the subordination period, assuming no additional issuances of common units (other than upon the conversion of the subordinated units), affiliates of our general partner will own approximately 81.7% of our aggregate outstanding common units. Affiliates of our general partner may acquire additional common units from us in connection with future transactions or through open-market or negotiated purchases.

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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 business, financial condition and results of operations and our 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 or to establish a nominating and corporate governance committee. 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, which we refer to herein as the Delaware 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.

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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.

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 a maximum of 35.0%, 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 condition and results of operations and our ability to make cash distributions to our 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.

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

The present federal income tax treatment of publicly traded partnerships, including us, or an investment in our common units may be modified by administrative, legislative or judicial interpretation at any time. From time to time, members of the U.S. Congress propose and consider substantive changes to the existing federal income tax laws that affect publicly traded partnerships. Additionally, on May 6, 2015, the IRS and the U.S. Department of the Treasury published proposed regulations that provide industry-specific guidance regarding whether income earned from certain activities will constitute qualifying income. 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, or whether proposed regulations, once issued in final form, will materially change interpretations of the current law, 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.

Our unitholders’ share of our income will be taxable to them for U.S. federal income tax purposes even if they do not receive any cash distributions from us.

Because a unitholder will be treated as a partner to whom we will allocate taxable income which could be different in amount than the cash we distribute, a unitholder’s allocable share of our taxable income will be taxable to it, which may require the payment of federal income taxes and, in some cases, state and local income taxes on such unitholder's share of our taxable income even if it receives no cash distributions from us. Our unitholders may not receive cash distributions from us equal to their share of our taxable income or even equal to the actual tax liability that results from that income.

In response to current market conditions, we may engage in transactions to deliver and manage our liquidity that may result in income and gain to our unitholders without a corresponding cash distribution. For example, if we sell assets and use the proceeds to repay existing debt or fund capital expenditures, our unitholders may be allocated taxable income and gain resulting from the sale without receiving a cash distribution. Further, taking advantage of opportunities to reduce our existing debt, such as debt exchanges, debt repurchases, or modifications of our existing debt could result in “cancellation of indebtedness income” (also referred to as “COD income”) being allocated to our unitholders as taxable income. Unitholders may be allocated COD income, and income tax liabilities arising therefrom may exceed cash distributions. The ultimate effect of any such allocations will depend on the unitholder's individual tax position with respect to its units. Unitholders are encouraged to consult their tax advisors with respect to the consequences to them of COD income.

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 our cash available for distribution to our unitholders might be substantially reduced.

Pursuant to the Bipartisan Budget Act of 2015, if the IRS makes audit adjustments to our income tax returns for tax years beginning after 2017, it may collect any resulting taxes (including any applicable penalties and interest) directly from us. We will generally have the ability to shift any such tax liability to our general partner and our unitholders in accordance with their interests in us during the year under audit, but there can be no assurance that we will be able to do so (and will choose to do so) 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, 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.

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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 unitholders sells will, in effect, become taxable income if such unitholders 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.

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 and will be taxable to them. 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. 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 will adopt 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 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 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 recently 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.

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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.

The sale or exchange of 50% or more of our capital and profits interests during any 12-month period will result in the termination of the Partnership for federal income tax purposes.

We will be considered to have technically terminated the Partnership for federal income tax purposes if there is a sale or exchange of 50% or more of the total interests in our capital and profits within a 12-month period. For purposes of determining whether the 50% threshold has been met, multiple sales of the same interest will be counted only once. Our technical termination would, among other things, result in the closing of our taxable year for all unitholders, which would result in us filing two tax returns (and our unitholders could receive two Schedules K-1 if relief was not available, as described below) for one fiscal year if the termination occurs on a day other than December 31 and could result in a deferral of depreciation deductions allowable in computing our taxable income. In the case of a unitholder reporting on a taxable year other than a fiscal year ending December 31, the closing of our taxable year may also result in more than 12 months of our taxable income or loss being includable in such unitholder's taxable income for the year of termination. Our termination currently would not affect our classification as a partnership for federal income tax purposes, but instead we would be treated as a new partnership for tax purposes. If treated as a new partnership, we must make new tax elections and could be subject to penalties if we are unable to determine that a termination occurred. The IRS has announced a publicly traded partnership technical termination relief program whereby, if a publicly traded partnership that technically terminated requests publicly traded partnership technical termination relief and such relief is granted by the IRS, among other things, the Partnership will only have to provide one Schedule K-1 to unitholders for the year notwithstanding two partnership tax years.

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 real property falls into two categories: (i) parcels that we own in fee and (ii) parcels in which our interest derives from leases, easements, rights-of-way, permits or licenses from landowners or governmental authorities permitting the use of such land for our operations. Certain of our processing plants and related facilities are located on land we own in fee, and management believes that we have satisfactory title to these lands. The remainder of the land on which our plants and related facilities are located is held by us pursuant to ground leases between us, or our subsidiaries, as lessee, and the fee owner of the lands, as lessors, and management believes that we have satisfactory leasehold estates to such lands. We have no knowledge of any challenge to the underlying fee title of any material lease, easement, right-of-way, permit or license held by us or to our title to any material lease, easement, right-of-way, permit or lease, and management believes that we have satisfactory title to all of our material leases, easements, rights-of-way, permits and licenses.

Record title to some of our assets may reflect names of prior owners until we have made the appropriate filings in the jurisdictions in which such assets are located. Title to some of our assets may be subject to encumbrances. Management believes that none of such encumbrances should materially detract from the value of our properties or our interest in those properties or should materially interfere with our use of them in the operation of our business. Substantially all of our pipelines are constructed on rights-of-way granted by the apparent owners of record of the properties. Lands over which pipeline rights-of-way have been obtained may be subject to prior liens that have not been subordinated to the rights-of-way grants.

Our principal executive offices are located at One Leadership Square, 211 North Robinson Avenue, Suite 150, Oklahoma City, Oklahoma 73102; our telephone number is 405-525-7788.

We currently occupy 162,053 square feet of office space at our principal executive offices under a lease that expires June 30, 2019. Although we may require additional office space as our business expands, management believes that our current facilities are adequate to meet our needs for the immediate future. In addition to our executive offices, we own numerous facilities throughout our service territory that support our operations. These facilities include, but are not limited to, district offices, fleet and equipment service facilities, compressor station facilities, operation support and other properties.

Please see Item 1. "Business — Our Assets and Operations" for further discussion of our property.

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 Combined and Consolidated Financial Statements. At the present time, based on currently available information, management believes that any reasonably possible losses in excess of accrued amounts arising out of pending or threatened lawsuits or claims would not be quantitatively material to our financial statements and would not have a material adverse effect on our consolidated financial position, results of operations or cash flows.

Item 4. Mine Safety Disclosures

Not applicable.

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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.” The following table sets forth the high and low closing prices of the common units as well as the amount of cash distributions declared and paid on the common units during each quarter since our Offering.

	Common Units		
	High	Low	Distribution per common unit
Year ended December 31, 2015			
Fourth Quarter	$13.97	$6.60	$0.318
Third Quarter	16.46	11.74	0.318
Second Quarter	17.80	15.98	0.316
First Quarter	19.75	16.19	0.3125
Year ended December 31, 2014			
Fourth Quarter	$24.93	$17.40	$0.30875
Third Quarter	26.75	23.78	0.3025
Second Quarter[1]	26.19	22.20	0.2464

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

On January 22, 2016, the Board of Directors declared a quarterly distribution of $0.318 per unit, which was paid on February 12, 2016, to unitholders of record at the close of business on February 2, 2016. The last reported sale price of our common units on the NYSE on February 1, 2016 was $7.30. As of February 1, 2016, there were 214,541,450 common units outstanding and approximately 14 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. We have also issued 207,855,430 subordinated units and ownership interests in the general partner, for which there is no established public trading market. All of the subordinated units and general partner interests are held by affiliates of our general partner.

Distributions of Available Cash

General

Our partnership agreement requires that, within 45 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; or
- provide funds for distributions to our unitholders and to our general partner for any one or more of the next four

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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);

- plus, if our general partner so determines, all or any portion of the cash on hand on the date of determination of available cash for the quarter resulting from working capital borrowings made subsequent to the end of such quarter.

Minimum Quarterly Distribution

The Minimum Quarterly Distribution, as set forth in the partnership agreement, is $0.2875 per unit per quarter, or $1.15 per unit on an annualized basis to the extent we have sufficient cash from our operations after the establishment of cash reserves and the payment of costs and expenses, including reimbursements of expenses to our general partner. Our current quarterly distribution is $0.318 per unit, or $1.272 per unit annualized. However, there is no guarantee that we will pay the minimum quarterly distribution on our units in any quarter. Even if our cash distribution policy is not modified or revoked, the amount of distributions paid under 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 Item 7. “Management’s Discussion and Analysis of Financial Condition and Results of Operations - Liquidity and Capital Resources” for a discussion of the restrictions included in our credit agreement that may restrict our ability to make distributions.

General Partner Interest and Incentive Distribution Rights

Enable GP owns a non-economic general partner interest in the Partnership and thus will not be entitled to distributions that the Partnership makes prior to the liquidation of the Partnership in respect of such general partner interest. Enable GP currently holds incentive distribution rights that entitle it to receive increasing percentages, up to a maximum of 50%, of the cash the Partnership distributes from operating surplus (as defined in our partnership agreement) in excess of $0.330625 per unit per quarter. The maximum distribution of 50% does not include any distributions that Enable GP or its affiliates may receive on common units or subordinated units that they own. Please read Note 5 of the Notes to Consolidated Financial Statements in Item 8. “Financial Statements and Supplementary Data” for additional information.

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 %

Subordination Period

General

Our partnership agreement provides that, during the subordination period (which we define below), the common units will have the right to receive distributions of available cash from operating surplus each quarter in an amount equal to $0.2875 per common unit, which amount is defined in our partnership agreement as the minimum quarterly distribution, plus any arrearages in the payment of the minimum quarterly distribution on the common units from prior quarters, before any distributions of available

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cash from operating surplus may be made on the subordinated units. These units are deemed "subordinated" because for a period of time, referred to as the subordination period, the subordinated units will not be entitled to receive any distributions until the common units have received the minimum quarterly distribution plus any arrearages from prior quarters. Furthermore, no arrearages will be paid on the subordinated units. The practical effect of the subordinated units is to increase the likelihood that during the subordination period there will be available cash to be distributed on the common units.

Definition of Subordination Period

Except as described below, the subordination period began on the closing date of the Offering and will extend until the first business day following the distribution of available cash in respect of any quarter beginning with the quarter ending June 30, 2017, that each of the following tests are met:

- distributions of available cash from operating surplus on each of the outstanding common units and subordinated units equaled or exceeded $1.15 per unit (the annualized minimum quarterly distribution), for each of the three consecutive, non-overlapping four-quarter periods immediately preceding that date;
- the adjusted operating surplus generated during each of the three consecutive, non-overlapping four-quarter periods immediately preceding that date equaled or exceeded the sum of $1.15 (the annualized minimum quarterly distribution) on all of the outstanding common units and subordinated units during those periods on a fully diluted basis; and
- there are no arrearages in payment of the minimum quarterly distribution on the common units.

Early Termination of Subordination Period

Notwithstanding the foregoing, the subordination period will automatically terminate on the first business day following the distribution of available cash in respect of any quarter beginning with the quarter ending June 30, 2015, that each of the following tests are met:

- distributions of available cash from operating surplus on each of the outstanding common units and subordinated units equaled or exceeded $1.725 (150% of the annualized minimum quarterly distribution) for the four-consecutive-quarter period immediately preceding that date;
- the adjusted operating surplus generated during the four-consecutive-quarter period immediately preceding that date equaled or exceeded the sum of (i) $1.725 per unit (150% of the annualized minimum quarterly distribution) on all of the outstanding common units and subordinated units during that period on a fully diluted basis and (ii) the corresponding distributions on the incentive distribution rights; and
- there are no arrearages in payment of the minimum quarterly distributions on the common units.

Expiration of the Subordination Period

When the subordination period ends, each outstanding subordinated unit will convert into one common unit and will thereafter participate pro rata with the other common units in distributions of available cash. In addition, if the unitholders remove our general partner other than for cause:

- the subordinated units held by any person will immediately and automatically convert into common units on a one-for-one basis, provided (i) neither such person nor any of its affiliates voted any of its units in favor of the removal and (ii) such person is not an affiliate of the successor general partner;
- if all of the subordinated units convert pursuant to the foregoing, all cumulative common unit arrearages on the common units will be extinguished and the subordination period will end; and
- 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.

Equity Compensation Plans

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

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Item 6. Selected Financial Data

The following tables set forth, for the periods and as of the dates indicated, the selected historical financial and operating data of Enable Midstream Partners, LP, which is derived from the historical books and records of the Partnership. On May 1, 2013 (formation), OGE Energy and ArcLight indirectly contributed 100% of the equity interests in Enogex to the Partnership in exchange for common units and, for OGE Energy only, interests in our general partner. The transaction was considered a business combination for accounting purposes, with the Partnership considered the acquirer of Enogex. Subsequent to May 1, 2013, the financial and operating data of the Partnership are consolidated to reflect the acquisition of Enogex and the retention of certain assets and liabilities by CenterPoint Energy.

	Year Ended December 31,				
	2015	2014	2013	2012	2011
	(In millions, except for per unit and operating data)				
Results of Operations Data:					
Revenues	$2,418	$3,367	$2,489	$952	$932
Cost of natural gas and natural gas liquids, excluding depreciation and amortization	1,097	1,914	1,313	129	101
Operation and maintenance, General and administrative	522	527	429	267	263
Depreciation and amortization	318	276	212	106	91
Impairments	1,134	8	12	—	—
Taxes other than income	59	56	54	34	37
Operating (loss) income	(712)	586	469	416	440
Interest expense	(90)	(70)	(67)	(85)	(90)
Equity in earnings of equity method affiliates	29	20	15	31	31
Interest income—affiliated companies	—	—	9	21	14
Step acquisition gain	—	—	—	136	—
Other, net	2	(1)	—	—	—
(Loss) income before income taxes	(771)	535	426	519	395
Income tax expense (benefit)	—	2	(1,192)	203	163
Net (loss) income	$(771)	$533	$1,618	$316	$232
Less: Net (loss) income attributable to noncontrolling interest	(19)	3	3	—	—
Net (loss) income attributable to Enable Midstream Partners, LP	$(752)	$530	$1,615	$316	$232
Limited partners' interest in net (loss) income attributable to Enable Midstream Partners, LP[1]	$(752)	$530	$289		
Basic and diluted (loss) earnings per common limited partner unit[1][2]	$(1.78)	$1.29	$0.74		
Basic and diluted (loss) earnings per subordinated limited partner unit[3]	$(1.78)	$1.28			
Distributions declared per unit[4]		$0.4534	$0.6086		
Distributions declared per unit[5]	$1.2645	$0.8577			
Balance Sheet Data (at period end):					
Property, plant and equipment, net	$10,131	$9,582	$8,990	$4,705	$4,070
Total assets	11,238	11,837	11,232	6,482	5,796
Long-term debt, including current portion	3,282	2,544	2,483	1,762	1,568
Enable Midstream Partners, LP Partners' Capital	7,519	8,792	8,148	3,215	2,898

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	Year Ended December 31,				
	2015	2014	2013	2012	2011
	(In millions, except for per unit and operating data)				
Cash Flow Data:					
Net cash flows provided by (used in):					
Operating activities	$726	$769	$648	$451	$662
Investing activities	(946)	(815)	(140)	(645)	(560)
Financing activities	212	(50)	(400)	194	(102)
Other Financial Data [(6)]:					
Gross margin	$1,321	$1,453	$1,176	$823	$831
Adjusted EBITDA	801	881	729	561	570
Distributable cash flow[(7)]	538	634	494		
Operating Data:					
Gathered volumes—TBtu	1,148	1,221	1,113	874	794
Gathered volumes—TBtu/d	3.14	3.34	3.05	2.39	2.17
Natural gas processed volumes—TBtu	651	569	397	73	37
Natural gas processed volumes—TBtu/d	1.78	1.56	1.09	0.20	0.10
NGLs produced—MBbl/d[(8)]	73.55	66.74	44.51	—	—
NGLs sold—MBbl/d[(8)(9)]	75.55	68.67	44.91	0.25	0.09
Condensate sold—MBbl/d	5.13	4.38	1.88	—	—
Crude Oil - Gathered volumes—MBbl/d[(10)]	13.86	3.64	—	—	—
Transported volumes—TBtu	1,814	1,808	1,608	1,378	1,596
Transportation volumes—TBtu/d	4.97	4.95	4.41	3.76	4.37
Interstate firm contracted capacity—Bcf/d	7.19	7.73	8.01	7.94	8.12
Intrastate average deliveries—TBtu/d	1.84	1.61	1.58	—	—

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

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

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

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

(5) Distributions attributable to periods subsequent to the Offering are in accordance with the Second Amended and Restated Agreement of Limited Partnership. Distributions declared per unit relate to common and subordinated units.

(6) See "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 Distributable Cash Flow to their most directly comparable financial measure calculated and presented in accordance with GAAP.

(7) Distributable cash flow attributable to periods in years prior to the year of our formation are not shown.

(8) Excludes condensate.

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

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

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

The following discussion and analysis should be read in conjunction with our combined and consolidated financial statements and the related notes included herein. The following discussion contains forward-looking statements that reflect our future plans, estimates, beliefs and expected performance. The forward-looking statements are dependent upon events, risks and uncertainties that may be outside our control. Our actual results could differ materially from those discussed in these forward-looking statements. Please read “Forward-Looking Statements.” In light of these risks, uncertainties and assumptions, the forward-looking events discussed may not occur.

Overview

We are a large-scale, growth-oriented publicly traded Delaware limited partnership formed to own, operate and develop strategically located natural gas and crude oil infrastructure assets. We serve current and emerging production areas in the United States, including several unconventional shale resource plays, and local and regional end-user markets in the United States. Our assets and operations are organized into two reportable segments: (i) Gathering and Processing, which primarily provides natural gas gathering, processing and fractionation services and crude oil gathering for our producer customers, and (ii) Transportation and Storage, which provides interstate and intrastate natural gas pipeline transportation and storage services primarily to natural gas producers, utilities and industrial customers.

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

We were formed in May 2013 as a limited partnership among CenterPoint Energy, OGE Energy and ArcLight. As of December 31, 2015, our portfolio of energy infrastructure assets included approximately 12,400 miles of gathering pipelines, 13 major processing plants with approximately 2.3 Bcf/d of processing capacity, approximately 7,900 miles of interstate pipelines (including SESH), approximately 2,200 miles of intrastate pipelines and eight natural gas storage facilities providing approximately 85.0 Bcf of storage capacity.

Our Operations

Our gathering and processing assets include approximately 12,400 miles of natural gas gathering pipelines in the Anadarko, Arkoma and Ark-La-Tex basins with approximately 976,000 horsepower of compression and 13 natural gas processing plants with approximately 2.3 Bcf/d of processing capacity and 2.3 Bcf/d of treating capacity as of December 31, 2015. We provide gathering, compression, treating, dehydration, processing and NGL fractionation for producers who are active in the areas in which we operate. For the year ended December 31, 2015, our assets gathered an average of approximately 3.14 TBtu/d of natural gas. For the year ended December 31, 2015, we processed approximately 1.78 TBtu/d of natural gas and produced approximately 73.55 MBbl/d of NGLs. We also have a crude oil gathering business in the Bakken Shale formation, principally located in the Williston Basin, that commenced initial operations in November 2013.

We provide fee-based interstate and intrastate transportation and storage services across nine states. We own and operate approximately 7,900 miles (including SESH) of interstate transportation pipelines with average firm contracted capacity of 7.19 Bcf/d (excluding SESH), for the year ended December 31, 2015. In addition, we own and operate approximately 2,200 miles of intrastate transportation pipelines with average aggregate throughput of 1.84 TBtu/d for the year ended December 31, 2015. We also own and operate eight natural gas storage facilities with approximately 85.0 Bcf of aggregate capacity and approximately 1.9 Bcf/d of aggregate daily deliverability as of December 31, 2015.

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

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

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

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How We Evaluate Our Operations

We use a variety of financial and operational metrics to analyze our performance. We view these metrics as important factors in evaluating our profitability and review these measurements on at least a monthly basis for consistency and trend analysis. These metrics are significant factors in assessing our operating results and profitability and include: (i) throughput volumes; (ii) gross margin; (iii) operation and maintenance and general and administrative expenses; (iv) Adjusted EBITDA and (v) distributable cash flow.

Throughput Volumes

The volume of natural gas that we gather, process, transport and store depends significantly on the level of production from natural gas wells connected to our systems. 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 rate of a natural gas well declines over time. Producers' willingness to engage in new drilling is determined by a number of factors, the most important of which are 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 and environmental and other government regulations. We generally expect the level of drilling to positively correlate with long-term trends in commodity prices. Similarly, production levels nationally and regionally generally tend to positively correlate with drilling activity.

To maintain and increase gathering throughput volumes on our systems, we must continue to contract our capacity to shippers, including producers and marketers. Our transportation and storage systems compete for customers based on the type of service a customer needs, operating flexibility, receipt and delivery points and geographic flexibility and available capacity and price. We actively monitor customer activity in the areas served by our systems to pursue new supply opportunities. To maintain and increase our transportation and storage volumes, we must continue to contract our capacity to shippers, including producers, marketers, LDCs, power generators and end-users.

Gross Margin

We view gross margin as an important performance measure of the core profitability of our business, as well as our operating performance as compared to that of other companies in our industry, without regard to financing methods, historical cost basis, capital structure or the impact of fluctuating commodity prices. We define gross margin as revenues minus costs of natural gas and natural gas liquids, excluding depreciation and amortization. Gross margin allows us to make a meaningful comparison of the operating results between our fee-based revenues, and our commodity-based contracts which involve the purchase or sale of natural gas, NGLs, and/or crude oil. In addition, gross margin allows us to make a meaningful comparison of the results of our commodity-based activities across different commodity price environments because it measures the spread between the product sales price and cost of products sold. Please read "—Results of Operations" and "—Non-GAAP Financial Measures" below.

Operation and Maintenance and General and Administrative Expenses

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 and repairs and maintenance expenses. These expenses generally remain relatively stable across broad ranges of throughput volumes but can fluctuate from period to period depending on the mix of activities performed during that period and the timing of these expenses. We seek to manage our maintenance expenditures on our assets by scheduling maintenance over time to avoid significant variability in our maintenance expenditures and minimize their impact on our system operations and cash flow.

The levels of exploration, development and production activities impact competition for personnel and equipment. Increased competition could place upward pressure on the prices we pay for labor, supplies and miscellaneous equipment. To the extent we are unable to procure necessary services or offset higher costs, should they occur, our operating results will be negatively impacted.

Adjusted EBITDA and Distributable Cash Flow

We define Adjusted EBITDA as net income from continuing operations before interest expense, income tax expense, depreciation and amortization expense and certain other items management believes affect the comparability of operating results. Distributable cash flow will not reflect changes in working capital balances. Please read "—Non-GAAP Financial Measures" below.

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Note About Non-GAAP Financial Measures

Gross margin, Adjusted EBITDA and distributable cash flow are not financial measures presented in accordance with GAAP. Management believes that the presentation of these non-GAAP financial measures will provide useful information to investors in assessing our financial condition and results of operations.

Revenue is the GAAP measure most directly comparable to gross margin, and net income attributable to controlling interest and net cash provided by operating activities are the GAAP measures most directly comparable to Adjusted EBITDA and distributable cash flow. Our non-GAAP financial measures should not be considered as alternatives to the most directly comparable GAAP financial measure. Each of these non-GAAP financial measures has important limitations as an analytical tool because it excludes some but not all items that affect the most directly comparable GAAP financial measure. Gross margin, Adjusted EBITDA and distributable cash flow should not be considered in isolation or as a substitute for analysis of our results as reported under GAAP. Because gross margin, Adjusted EBITDA and distributable cash flow may be defined differently by other companies in our industry, our definitions of these non-GAAP financial measures may not be comparable to similarly titled measures of other companies, thereby diminishing their utility.

Management compensates for the limitations of gross margin, Adjusted EBITDA and distributable cash flow as analytical tools by reviewing the comparable GAAP measures, understanding the differences between gross margin, Adjusted EBITDA and distributable cash flow, on the one hand, and revenue, net income and net cash provided by operating activities, on the other hand, and incorporating this knowledge into its decision-making processes. Management believes that investors benefit from having access to the same financial measures that our management uses in evaluating our operating results. For a reconciliation of gross margin, Adjusted EBITDA and distributable cash flow to their most directly comparable financial measures calculated and presented in accordance with GAAP, please read "—Non-GAAP Financial Measures" below.

Items Affecting the Comparability of Our Financial Results

Our future results of operations may not be comparable to our historical results of operations for the reasons described below.

Formation of Partnership. For accounting purposes, we treat the formation of our partnership on May 1, 2013 as an acquisition, with the Partnership as the acquirer of Enogex. As a result, our historical results of operations for periods prior to May 1, 2013 do not include the results of Enogex's operations.

Operation and Maintenance and General and Administrative Expenses. We have entered into services agreements with each of CenterPoint Energy and OGE Energy pursuant to which they perform certain administrative services for us that are generally consistent with the level and type of services they provided to each of their respective businesses prior to our formation. At formation, these services included accounting, finance, legal, risk management, information technology and human resources. 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. Our reimbursement obligations are capped at amounts set forth in our annual budget. The initial term of the services agreements ends in May 2016, after which date they continue on a year-to-year basis unless terminated by us upon 90 days' notice. Subject to the provisions of the service agreements, we terminated use of a significant portion of these services as we now perform many of the services internally.

Historically, our general and administrative expenses included direct monthly charges for the management and operation of our logistics assets and certain expenses allocated by our sponsors for general corporate services, such as treasury, accounting and legal services. These expenses were charged or allocated to us based on conventions accepted by the regulators of CenterPoint Energy's and OGE Energy's regulated utility assets. For additional information, please see Note 14 to the Combined and Consolidated Financial Statements for the years ended December 31, 2015, 2014 and 2013.

Income Tax Expenses. Prior to May 1, 2013, our assets were included in CenterPoint Energy’s consolidated federal income tax returns, which were taxed at the entity level as a C corporation. Following our formation, we are treated as a partnership for federal income tax purposes, with each partner being separately taxed on its share of taxable income; therefore, there is no income tax expense in our financial statements subsequent to May 1, 2013 (other than Texas state margin taxes and taxes associated with the Partnership's corporate subsidiary, Enable Midstream Services). As a result of the conversion to a limited partnership, we recorded a one-time income tax benefit of $1.24 billion in the year ended December 31, 2013.

Financing. Upon our formation, we entered into our $1.05 billion three-year term loan facility (2013 Term Loan Facility), the proceeds of which were used to repay $1.05 billion of intercompany indebtedness owed to CenterPoint Energy. In addition,

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upon our formation, we entered into a $1.4 billion five-year revolving credit facility. Initial advances under the $1.4 billion revolving credit facility were used for general partnership purposes and to refinance a revolving credit facility held by Enogex, which was terminated in connection with our formation, and existing indebtedness owing by Enogex to OGE Energy as of May 1, 2013.

In January 2014, we initiated our $1.4 billion commercial paper program. This program is used for general corporate purposes. Commercial paper issuances effectively reduce our borrowing capacity under our current Revolving Credit Facility. In April 2014, the Partnership completed the Offering of 25,000,000 units and received net proceeds of $464 million. The Partnership retained the net proceeds of the Offering for general partnership purposes, including the funding of expansion capital expenditures, and to pre-fund demand fees expected to be incurred over the next three years relating to certain expiring transportation and storage contracts. On May 27, 2014, the Partnership completed the private offering of 2019 Notes, 2024 Notes and 2044 Notes, with registration rights. The Partnership received aggregate proceeds of $1.63 billion. Certain of the proceeds were used to repay the 2013 Term Loan Facility, and certain of the proceeds were used to repay the EOIT $250 million variable rate term loan and the EOIT $200 million 6.875% senior notes due July 15, 2014, and for general corporate purposes. See Note 10 for discussion of the repayment of the EOIT $200 million 6.875% senior notes. A wholly owned subsidiary of CenterPoint Energy has guaranteed collection of the Partnership's obligations under the 2019 Notes and 2024 Notes, on an unsecured subordinated basis, subject to automatic release on May 1, 2016.

On June 18, 2015, the Partnership amended and restated its Revolving Credit Facility to, among other things, increase the borrowing capacity thereunder to $1.75 billion and extend its maturity date to June 18, 2020. On July 31, 2015, the Partnership entered into a term loan agreement providing for an unsecured three-year $450 million term loan facility (2015 Term Loan Facility). Please read "—Liquidity and Capital Resources".

On January 28, 2016, the Partnership entered into an agreement with CenterPoint Energy to issue and sell in a Private Placement an aggregate of 14,520,000 Preferred Units for a cash purchase price of $25.00 per Preferred Unit, resulting in total gross proceeds of $363 million. The closing of the Private Placement, which is expected to occur prior to the end of the first quarter of 2016, is subject to the completion of due diligence by CenterPoint Energy, including the review of the Partnership's audited financial statements and this Form 10-K, and certain customary closing conditions. In connection with the Private Placement, the Partnership intends to redeem the $363 million of Notes payable—affiliated companies scheduled to mature in 2017 payable to a subsidiary of CenterPoint Energy. For a further discussion regarding the Private Placement, see "—Liquidity and Capital Resources—Equity Issuances."
Cash Distributions. Our partnership agreement requires that we distribute to our unitholders quarterly all of our available cash. As a result, we expect to fund future capital expenditures primarily from external sources, including borrowings under our Revolving Credit Facility, issuances of commercial paper, when available, and future issuances of equity and debt securities.

General Trends and Outlook

We expect our business to continue to be affected by the key trends discussed below. Our expectations are based on assumptions made by us and information currently available to us. To the extent our underlying assumptions about, or interpretations of, available information prove to be incorrect, our actual results may vary materially from our expected results.

Commodity Price Volatility

Prices of natural gas, crude oil and NGLs have historically experienced periods of significant volatility. Commodity price changes impact the commodity-based portion of our gross margin, our producer customers' decisions to drill and complete wells and our transportation and storage customers’ decisions to contract capacity on our systems. Our results are also impacted by the price differentials between receipt and delivery points on our systems. 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. The prices of crude oil, NGLs and natural gas have continued to decline significantly. Over the course of 2015 and continuing into 2016, natural gas and crude oil prices have dropped to their lowest levels in over 10 years from a high of $13.31 per MMBtu in July 2008 to $1.63 MMBtu at December 23, 2015 and $145.31 per barrel in July 2008 to $26.19 per barrel at February 11, 2016, respectively. Should lower commodity prices persist, or should commodity prices decline further, our future volumes and cash flows may be negatively impacted. For additional information regarding our commodity price risk, see Item 7A. "Quantitative and Qualitative Disclosures About Market Risk - Commodity Price Risk.”

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Growth in Production of U.S. Shale Plays

Over the past several years, there has been a fundamental shift in U.S. natural gas and crude oil production towards tight gas formations and shale plays. The emergence of these plays and advancements in technology have been crucial factors that have allowed producers to efficiently extract significant volumes of natural gas and crude oil. Recently, declining crude oil, natural gas and NGL prices have resulted in decreases in current and anticipated crude oil and natural gas drilling activity. Should lower prices and producer activity persist for a sustained period, or should prices and producer activity decline further, our future volumes and cash flows may be negatively impacted.

Natural Gas Supply and Demand Dynamics

Natural gas continues to be a critical component of energy supply and demand in the United States. Over the long term, management believes that the prospects for continued natural gas demand are favorable and will be driven by population and economic growth, as well as the continued displacement of coal-fired electricity generation by natural gas-fired electricity generation due to the low prices of natural gas and stricter government environmental regulations on the mining and burning of coal. According to the EIA, demand for natural gas in the electric power sector is projected to increase from approximately 8.2 Tcf in 2013 to approximately 9.4 Tcf in 2040, with a portion of the growth attributable to the retirement of 37 gigawatts of coal-fired capacity by 2020. The EIA also predicts that low natural gas prices will lead to the increase of natural gas consumption in the industrial sector and to the United States becoming a net exporter of natural gas by mid-2017. However, the EIA expects growth in natural gas consumption for power generation, exportation and in the industrial sector to be partially offset by decreased usage in the residential sector. Management believes that increasing consumption of natural gas over the long term will continue to drive demand for our natural gas gathering, processing, transportation and storage services.

Capital Market Volatility

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

Regulatory Compliance

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

Workforce Reductions

On February 16, 2015, management of the Partnership announced to its employees that during 2015, the Partnership planned to reduce its then-current workforce by approximately 10% and consolidate certain administrative functions to its Oklahoma City, Oklahoma and Houston, Texas offices in order to reduce costs and improve efficiency. As part of the announced workforce reduction, management identified certain reductions that would continue into 2016. Impacted employees were provided with severance payments during 2015 or will be provided with severance payments during 2016. The intent of these actions is to reduce Operating and maintenance and General and administrative expense and improve efficiency over the long term, with savings of approximately $20 million per year anticipated after 2016.

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Results of Operations

The historical 2013 financial information included below reflects the combined assets, liabilities and operations of the entities comprising CenterPoint Energy's reportable segments for the periods of January 1, 2013 to May 1, 2013 and the consolidated assets, liabilities and operations of these reportable segments of the Partnership for the period of May 1, 2013 to December 31, 2013 and thereafter.

December 31, 2015	Gathering and Processing	Transportation and Storage	Eliminations	Enable Midstream Partners, LP
	(In millions)			
Revenues	$1,663	$1,132	$(377)	$2,418
Cost of natural gas and natural gas liquids (excluding depreciation and amortization shown separately)	908	565	(376)	1,097
Gross margin[1]	755	567	(1)	1,321
Operation and maintenance, General and administrative	293	230	(1)	522
Depreciation and amortization	195	123	—	318
Impairments	543	591	—	1,134
Taxes other than income tax	30	29	—	59
Operating (loss) income	$(306)	$(406)	$—	$(712)
Equity in earnings of equity method affiliates	$—	$29	$—	$29

December 31, 2014	Gathering and Processing	Transportation and Storage	Eliminations	Enable Midstream Partners, LP
	(In millions)			
Revenues	$2,424	$1,577	$(634)	$3,367
Cost of natural gas and natural gas liquids (excluding depreciation and amortization shown separately)	1,585	961	(632)	1,914
Gross margin[1]	839	616	(2)	1,453
Operation and maintenance, General and administrative	297	232	(2)	527
Depreciation and amortization	160	116	—	276
Impairments	8	—	—	8
Taxes other than income tax	25	31	—	56
Operating income	$349	$237	$—	$586
Equity in earnings of equity method affiliates	$—	$20	$—	$20

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December 31, 2013	Gathering and Processing	Transportation and Storage	Eliminations	Enable Midstream Partners, LP
	(In millions)			
Revenues	$1,740	$1,149	$(400)	$2,489
Cost of natural gas and natural gas liquids (excluding depreciation and amortization shown separately)	1,075	636	(398)	1,313
Gross margin[1]	665	513	(2)	1,176
Operation and maintenance, General and administrative	222	209	(2)	429
Depreciation and amortization	117	95	—	212
Impairments	12	—	—	12
Taxes other than income tax	20	34	—	54
Operating income	$294	$175	$—	$469
Equity in earnings of equity method affiliates	$—	$15	$—	$15

(1) Gross margin is defined and reconciled to its most directly comparable financial measures calculated and presented below under the caption Non-GAAP Financial Measure.

	Year Ended December 31, 2015	2014	2013
Operating Data:			
Gathered volumes—TBtu	1,148	1,221	1,113
Gathered volumes—TBtu/d[1]	3.14	3.34	3.05
Natural gas processed volumes—TBtu	651	569	397
Natural gas processed volumes—TBtu/d[1]	1.78	1.56	1.09
NGLs produced—MBbl/d[1][2]	73.55	66.74	44.51
NGLs sold—MBbl/d[1][2][3]	75.55	68.67	44.91
Condensate sold—MBbl/d[1]	5.13	4.38	1.88
Crude Oil—Gathered volumes—MBbl/d[4]	13.86	3.64	—
Transported volumes—TBtu	1,814	1,808	1,608
Transportation volumes—TBtu/d[1]	4.97	4.95	4.41
Interstate firm contracted capacity—Bcf/d[1]	7.19	7.73	8.01
Intrastate average deliveries—TBtu/d[1]	1.84	1.61	1.58

(1) 2013 daily averages are computed utilizing a 365 day convention, and are not computed using a weighted average convention for the acquisition of Enogex.
(2) Excludes condensate.
(3) NGLs sold includes volumes of NGLs withdrawn from inventory or purchased for system balancing purposes.
(4) Initial operation of our crude oil gathering system began on November 1, 2013.

Gathering and Processing

2015 compared to 2014. Our gathering and processing segment reported operating loss of $306 million for the year ended December 31, 2015 compared to operating income of $349 million in the year ended December 31, 2014. Operating income decreased $655 million primarily from impairment charges of $543 million related to the impairment of goodwill and long-lived assets, decreased gross margin of $84 million, an increase in depreciation and amortization of $35 million, and an increase in taxes other than income tax of $5 million, partially offset by a decrease of $4 million in operation and maintenance and general and administrative expenses during the year ended December 31, 2015.

Our gathering and processing segment gross margin decreased $84 million primarily due to a decrease in processing margins
of $66 million resulting from the impact of lower average natural gas liquids prices and lower processed volumes in the Ark-La-Tex basin offset by higher processed volumes in the Anadarko and Arkoma basins. Also, gathering margins decreased due to reduced sales on natural gas length of $25 million and decreased gathering fees of $14 million, as a result of lower gathered volumes in the Arkoma and Ark-La-Tex basins and lower average natural gas prices partially offset by higher gathered volumes

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in the Anadarko basin, net of minimum volume payments, and lower revenues on third party measurement and communication services of $4 million. These decreases were partially offset by increases in crude oil gathered volumes in the Williston basin of $12 million, one time project reimbursements of $11 million and a $2 million increase in unrealized gains on condensate and NGL derivatives during the year ended December 31, 2015.

Our gathering and processing segment operation and maintenance and general and administrative expenses decreased $4 million primarily due to workforce reductions and lower payroll related costs of $13 million, lower write down of materials and supplies inventory of $4 million, and lower losses on sale of assets of $2 million. These decreases were partially offset by expenses for one time project costs of $9 million and payroll expenses for severance payments related to workforce reductions of $6 million.

Our gathering and processing segment depreciation and amortization expense increased $35 million due to additional assets placed in service.

Our gathering and processing segment recognized impairments of $543 million and $8 million in the years ended December 31, 2015 and 2014, respectively. Due to the continuing commodity price declines, the resulting decreases in forward commodity prices and forecasted producer activities, and an increase in the weighted average cost of capital, in its preparation of financial statements for the third quarter of 2015, the Partnership determined that the carrying value of goodwill associated with the gathering and processing reportable segment was completely impaired and recognized $508 million of impairment. The Partnership also determined that the carrying value of the Atoka assets were impaired and recognized $25 million of impairment. Additionally, the impairment on the Service Star business line increased $3 million during 2015, which was offset by lower impairment of assets held for sale of $1 million.

Our gathering and processing segment taxes other than income tax increased $5 million due to additional assets placed in service of $2 million and the effect of a favorable settlement of a state and local tax dispute in 2014 for $3 million less than the previously recognized reserve.

2014 compared to 2013. Our gathering and processing segment reported operating income of $349 million in the year ended December 31, 2014 compared to $294 million in the year ended December 31, 2013. Operating income increased $55 million primarily from increased gross margin of $174 million and a decrease in impairments of $4 million, partially offset by an increase in operation and maintenance and general and administrative expenses of $75 million, an increase in depreciation and amortization of $43 million, and an increase in taxes other than income tax of $5 million, during the year ended December 31, 2014.

Our gathering and processing segment gross margin increased $174 million primarily due to the 2013 acquisition of Enogex, resulting in an increase to gross margin of $138 million, higher average natural gas prices of $9 million, higher processing margin of $35 million due to increased processed volumes in the Anadarko and Ark-La-Tex basins, unrealized gains on condensate derivatives of $5 million, and the addition of gross margin on our crude oil gathering business of $5 million, partially offset by higher cost of goods sold on third party measurement and communication services of $7 million and decreased gathered volumes in the Ark-La-Tex and Arkoma basins of $11 million, net of minimum volume payments.

Our gathering and processing segment operation and maintenance and general and administrative expenses increased $75 million primarily due to the 2013 acquisition of Enogex, which contributed $51 million of operation and maintenance and general and administrative expenses, as well as an increase in payroll-related expenses of $6 million from increased head count to support business growth, an increase in integration costs of $6 million, an increase in general operating and maintenance expenses of $11 million to support and operate new assets, a write down of materials and supplies inventory of $4 million and a loss on sale of assets of $1 million, partially offset by $4 million due to lower third party measurement and communications services expenses.

Our gathering and processing segment depreciation and amortization increased $43 million due to the depreciation on assets related to the 2013 acquisition of Enogex of $31 million and $12 million due to depreciation on assets placed in service.

Our gathering and processing segment recognized impairments of $8 million and $12 million in the years ended December 31, 2014 and 2013, respectively. Due to the cancellation of services by additional customers during 2014, management reassessed the carrying value of the Service Star business line, which resulted in the 2014 impairment. Therefore, the $4 million decrease was primarily due to the decrease in the Service Star impairment of $5 million, offset by additional impairments of other assets of $1 million in 2014.

Our gathering and processing segment taxes other than income tax increased $5 million due to increased ad valorem taxes as a result of additional assets in service related to the 2013 acquisition of Enogex of $4 million, and other additional assets placed in service of $4 million. These increases were partially offset by the favorable settlement of a state and local tax dispute for $3 million less than the previously recognized reserve.

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Transportation and Storage

2015 compared to 2014. Our transportation and storage segment reported operating loss of $406 million in the year ended December 31, 2015 compared to operating income of $237 million in the year ended December 31, 2014. Operating income decreased $643 million primarily resulting from impairment charges of $591 million primarily related to the impairment of goodwill, a decrease in gross margin of $49 million, and a $7 million increase in depreciation and amortization expenses, partially offset by a decrease of $2 million in operation and maintenance and general and administrative expenses and a decrease in taxes other than income tax of $2 million during the year ended December 31, 2015.

Our transportation and storage segment gross margin decreased $49 million primarily due to lower margin on unrealized natural gas derivatives of $45 million, a decrease in sales of NGLs collected under contractual arrangements of $19 million resulting from lower NGL prices, lower firm transportation revenues of $12 million, a decrease in storage demand fees of $6 million as well as lower rates on transportation services for local distribution companies of $4 million. These decreases were partially offset by higher margins of $32 million related to realized gains on system optimization activities and increased margins from higher rates on off-system transportation services of $5 million for the year ended December 31, 2015.

Our transportation and storage segment operation and maintenance and general and administrative expenses decreased $2 million due to lower write down of materials and supplies inventory of $2 million and lower payroll related costs of $2 million related to workforce reductions. This decrease was offset by higher payroll expenses for severance payments related to workforce reductions of $2 million.

Our transportation and storage segment depreciation and amortization expense increased $7 million primarily due to additional assets placed in service.

During 2015 our transportation and storage segment recognized impairment charges of $591 million. Due to continuing commodity price declines, the resulting decreases in forward commodity prices and forecasted producer activities, and an increase in the weighted average cost of capital, the Partnership determined that the carrying value of goodwill associated with the transportation and storage reportable segment was completely impaired and as a result recognized impairment expense of $579 million in 2015. Additionally, we recognized an impairment on jurisdictional pipeline assets of $12 million in 2015.

Our transportation and storage segment taxes other than income tax decreased $2 million due to reduced ad valorem taxes.

Our transportation and storage segment recorded equity in earnings of equity method affiliates of $29 million and $20 million for the years ended December 31, 2015 and 2014, respectively, from our interest in SESH. The $9 million increase in equity earnings from equity method affiliates is attributable to our increased interest in SESH for the year ended December 31, 2015 as compared to the year ended December 31, 2014.

2014 compared to 2013. Our transportation and storage segment reported operating income of $237 million in the year ended December 31, 2014 compared to $175 million in the year ended December 31, 2013. Operating income increased $62 million primarily resulting from an increase in gross margin of $103 million and a decrease in taxes other than income tax of $3 million, partially offset by an increase of $23 million in operation and maintenance and general and administrative expenses, as well as an increase of $21 million in depreciation and amortization during the year ended December 31, 2014.

Our transportation and storage segment gross margin increased $103 million primarily due to the 2013 acquisition of Enogex, which contributed $47 million to gross margin, as well as an increase in unrealized gains on natural gas derivatives of $32 million, an increase from system optimization activities of $12 million, an increase from operational synergies of $3 million, an increase from off-system transportation revenues of $6 million, higher rates on transportation services for local distribution companies of $9 million, and higher other firm transportation revenues of $4 million, partially offset by a decrease in storage demand fees of $9 million and balancing services of $1 million.

Our transportation and storage segment operation and maintenance and general and administrative expenses increased $23 million due to the 2013 acquisition of Enogex, which contributed $19 million to operation and maintenance and general and administrative expenses, an increase in payroll-related expense of $23 million from increased head count to support business growth, an increase in general operating and maintenance expenses of $5 million to support and operate new assets, and a write down of materials and supplies inventory of $2 million, partially offset by a decrease in relocation costs of $4 million, a decrease in allocated corporate service costs of $15 million, and a litigation settlement of $5 million in 2013, offset in 2014 by $2 million of insurance proceeds.

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Our transportation and storage segment depreciation and amortization expense increased $21 million primarily due to the additional assets in service from the 2013 acquisition of Enogex of $16 million, MRT rate case impact of $1 million and asset additions of $4 million.

Our transportation and storage segment taxes other than income tax decreased $3 million due to reduced ad valorem taxes on intangible assets of $6 million, partially offset by the 2013 acquisition of Enogex, which contributed $3 million.

Our transportation and storage segment recorded equity in earnings of equity method affiliates of $20 million and $15 million for the years ended December 31, 2014 and 2013, respectively, from our interest in SESH. The $5 million increase is attributable to the 24.95% interest in SESH contributed by CenterPoint Energy on May 30, 2014 to the Partnership.

Combined and Consolidated Information

	Year Ended December 31,		
	2015	2014	2013
	(In millions)		
Operating (Loss) Income	$(712)	$586	$469
Other Income (Expense):			
Interest expense	(90)	(70)	(67)
Equity in earnings of equity method affiliates	29	20	15
Interest income—affiliated companies	—	—	9
Other, net	2	(1)	—
Total Other Income (Expense)	(59)	(51)	(43)
(Loss) Income Before Income Taxes	(771)	535	426
Income tax expense (benefit)	—	2	(1,192)
Net (Loss) Income	$(771)	$533	$1,618
Less: Net (loss) income attributable to noncontrolling interest	(19)	3	3
Net (Loss) Income attributable to Enable Midstream Partners, LP	$(752)	$530	$1,615

	Year Ended December 31,		
	2015	2014	2013
	(In millions)		
Other Financial Data:			
Gross Margin (1)	$1,321	$1,453	$1,176
Adjusted EBITDA (1)	801	881	729
Distributable cash flow (1)	538	634	494

(1) Gross margin, Adjusted EBITDA and distributable cash flow are defined and reconciled to their most directly comparable financial measures calculated and presented below under the caption Non-GAAP Financial Measure.

2015 compared to 2014

Net (Loss) Income attributable to the Partnership. We reported net loss attributable to the Partnership of $752 million in the year ended December 31, 2015 compared to net income attributable to the Partnership of $530 million in the year ended December 31, 2014. The decrease in net income attributable to the Partnership of $1,282 million was primarily attributable to a decrease in operating income of $1,298 million (inclusive of impairments discussed by segment above) and an increase in interest expense of $20 million, partially offset by an increase in equity earnings in equity method affiliates of $9 million (discussed by segment above).

Interest Expense. Interest expense increased $20 million due to higher interest rates on the Partnership's outstanding debt and an increase in the amount of debt outstanding.

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2014 compared to 2013

Net Income attributable to the Partnership. We reported net income attributable to the Partnership of $530 million and $1,615 million in the years ended December 31, 2014 and 2013, respectively. The decrease in net income attributable to the Partnership of $1,085 million was primarily attributable to the 2013 recognition of a $1,194 million income tax benefit upon conversion to a limited partnership, net of taxes incurred prior to the conversion, an increase in other income and expense related to the loss on extinguishment of debt of $1 million, an increase in interest expense of $3 million and a decrease in interest income of $9 million as a result of the reduction in notes receivable. These increases were partially offset by an increase in equity earnings in equity method affiliates of $5 million (discussed by reportable segment above) and an increase in operating income of $117 million inclusive of the $50 million impact of the 2013 acquisition of Enogex discussed by segment above.

Interest Expense. Interest expense increased $3 million, primarily due to a $10 million increase in interest expense incurred on the debt assumed with the 2013 acquisition of Enogex, partially offset by a decrease of $7 million related to lower interest rates on the Partnership's other outstanding debt.

Income Tax Expense. Effective May 1, 2013, upon conversion to a limited partnership, the Partnership’s earnings are no longer subject to income taxes (other than Texas state margin taxes and taxes associated with the Partnership's corporate subsidiary, Enable Midstream Services). As a result of the conversion to a partnership, we recognized our outstanding current income tax liabilities and deferred income tax assets and liabilities by recording an income tax benefit of $1,194 million, net of taxes incurred prior to the conversion. Consequently, the Combined and Consolidated Statement of Income for the year ended December 31, 2014 does not include an income tax provision (other than Texas state margin taxes and taxes associated with the Partnership's corporate subsidiary, Enable Midstream Services).

Non-GAAP Financial Measures

The Partnership has included the non-GAAP financial measures gross margin, Adjusted EBITDA and distributable cash flow in this report based on information in its combined and consolidated financial statements.
Gross margin, Adjusted EBITDA and distributable cash flow are supplemental financial measures that management and external users of the Partnership’s financial statements, such as industry analysts, investors, lenders and rating agencies may use, to assess:

- The Partnership’s operating performance as compared to those of other publicly traded partnerships in the midstream energy industry, without regard to capital structure or historical cost basis;
- The ability of the Partnership’s assets to generate sufficient cash flow to make distributions to its partners;
- The Partnership’s ability to incur and service debt and fund capital expenditures; and
- The viability of acquisitions and other capital expenditure projects and the returns on investment of various investment opportunities.

This report includes a reconciliation of gross margin to revenues, Adjusted EBITDA and distributable cash flow to net income attributable to controlling interest, and Adjusted EBITDA to net cash provided by operating activities, the most directly comparable GAAP financial measures, on a historical basis, as applicable, for each of the periods indicated. The Partnership believes that the presentation of gross margin, Adjusted EBITDA and distributable cash flow provides information useful to investors in assessing its financial condition and results of operations. Gross margin, Adjusted EBITDA and distributable cash flow should not be considered as alternatives to net income, operating income, revenue, cash from operations or any other measure of financial performance or liquidity presented in accordance with GAAP. Gross margin, Adjusted EBITDA and distributable cash flow have important limitations as an analytical tool because they exclude some but not all items that affect the most directly comparable GAAP measures. Additionally, because gross margin, Adjusted EBITDA and distributable cash flow may be defined differently by other companies in the Partnership's industry, its definitions of gross margin, Adjusted EBITDA and distributable cash flow may not be comparable to similarly titled measures of other companies, thereby diminishing their utility.

	Year Ended December 31,		
	2015	2014	2013
	(In millions)		
Reconciliation of Gross Margin to Revenues:			
Revenues	$2,418	$3,367	$2,489
Cost of natural gas and natural gas liquids (excluding depreciation and amortization)	1,097	1,914	1,313
Gross margin	$1,321	$1,453	$1,176
Reconciliation of Adjusted EBITDA and distributable cash flow to net (loss) income attributable to controlling interest:			
Net (loss) income attributable to Enable Midstream Partners, LP	$(752)	$530	$1,615
Add:			
Depreciation and amortization expense	318	276	212
Interest expense, net of interest income	90	70	58
Income tax expense (benefit)	—	2	(1,192)
EBITDA	$(344)	$878	$693
Add:			
Loss on extinguishment of debt	—	4	—
Distributions from equity method affiliates (1)	42	23	24
Non-cash equity based compensation (2)	9	13	—
Other non-cash losses	36	22	15
Impairments	1,134	8	12
Less:			
Other non-cash gains	(27)	(46)	—
Noncontrolling Interest Share of Adjusted EBITDA	(20)	(1)	—
Equity in earnings of equity method affiliates	(29)	(20)	(15)
Adjusted EBITDA	$801	$881	$729
Less:			
Adjusted interest expense, net (3)	(102)	(82)	(69)
Maintenance capital expenditures	(160)	(164)	(164)
Current income taxes(4)	(1)	(1)	(2)
Distributable cash flow	$538	$634	$494

(1) Excludes $198 million in special distributions for the return of investment in SESH for the year ended December 31, 2014.
(2) In the fourth quarter of 2015, the calculation of Adjusted EBITDA was modified to account for non-cash equity based compensation expense to be consistent with industry peers.
(3) Adjusted interest expense, net excludes the effect of the amortization of the premium on EOIT’s fixed rate senior notes. This exclusion is the primary reason for the difference between “Interest expense, net” and “Adjusted interest expense, net.”
(4) In the second quarter of 2015, the calculation of Distributable cash flow was modified to account for current income tax expense to be consistent with industry peers.

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	Year Ended December 31,		
	2015	2014	2013
	(In millions)		
Reconciliation of Adjusted EBITDA to net cash provided by operating activities:			
Net cash provided by operating activities	$726	$769	$648
Interest expense, net of interest income	90	70	58
Net loss (income) attributable to noncontrolling interest	19	(3)	(3)
Income tax expense (benefit)	—	2	(1,192)
Deferred income tax (expense) benefit	1	(1)	1,194
Equity in earnings of equity method affiliates, net of distributions (1)	(13)	(3)	(9)
Impairments	(1,134)	(8)	(12)
Non-cash equity based compensation	(9)	(13)	—
Other non-cash items	5	1	(1)
Changes in operating working capital which (provided) used cash:			
Accounts receivable	(15)	(53)	85
Accounts payable	29	140	(65)
Other, including changes in noncurrent assets and liabilities	(43)	(23)	(10)
EBITDA	$(344)	$878	$693
Add:			
Impairments	1,134	8	12
Non-cash equity based compensation (2)	9	13	—
Loss on extinguishment of debt	—	4	—
Distributions from equity method affiliates (1)	42	23	24
Other non-cash losses	36	22	15
Less:			
Other non-cash gains	(27)	(46)	—
Noncontrolling Interest Share of Adjusted EBITDA	(20)	(1)	—
Equity in earnings of equity method affiliates	(29)	(20)	(15)
Adjusted EBITDA	$801	$881	$729

(1) Excludes $198 million in special distributions for the return of investment in SESH for the year ended December 31, 2014.
(2) In the fourth quarter of 2015, the calculation of Adjusted EBITDA was modified to account for non-cash equity based compensation expense to be consistent with industry peers.

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, borrowings under our revolving credit facility, debt issuances and the issuance of equity. Historically, our liquidity and capital resource needs have been met by these sources and, prior to 2014, contributions by CenterPoint Energy, OGE Energy and ArcLight. However, issuances of equity or debt in the capital markets, funds raised in the commercial paper 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. On February 2, 2016, Standard & Poor's Ratings Services lowered its credit rating on the Partnership from an investment grade rating to a non-investment grade rating. The short-term rating on the Partnership was also reduced from an investment grade rating to a non-investment grade rating. As a result, we expect our access to our commercial paper program to be limited until these ratings improve. Factors that contribute to our ability to raise capital through these channels depend on our financial condition, credit ratings and market conditions. Our ability to generate cash flow is subject to a number of factors, some of which are beyond our control. See Item 1A. "Risk Factors" for further discussion.

Working Capital

Working capital is the difference in our current assets and our current liabilities. Working capital is an indication of liquidity and potential need for short-term funding. The change in our working capital requirements are driven generally by changes in accounts receivable, accounts payable, commodity prices, credit extended to, and the timing of collections from, customers, and the level and timing of spending for maintenance and expansion activity. As of December 31, 2015, we had a working capital deficit of $234 million due primarily to borrowings under our commercial paper program to manage the timing of cash flows for maintenance and expansion activity. Historically, we have utilized our commercial paper program and Revolving Credit Facility to manage the timing of cash flows and fund short-term working capital deficits. However, issuances of equity or debt in the capital markets, funds raised in the commercial paper markets and additional credit facilities may not be available to us on acceptable terms.

Cash Flows

The following tables reflect cash flows for the applicable periods:

	Year Ended December 31,		
	2015	2014	2013
	(In millions)		
Net cash provided by operating activities	$726	$769	$648
Net cash used in investing activities	(946)	(815)	(140)
Net cash provided by (used in) financing activities	212	(50)	(400)

Operating Activities

The decrease of $43 million, or 6%, in net cash provided by operating activities for the year ended December 31, 2015 as compared to the year ended December 31, 2014 is primarily due to lower gross margin, which was partially offset by the impact of timing of payments to suppliers, receipts from customers, and changes in other working capital assets and liabilities.

The increase of $121 million, or 19%, in net cash provided by operating activities for the year ended December 31, 2014 as compared to the year ended December 31, 2013 is due to the impact of timing of payments and receipts on changes in assets and liabilities partially offset by:

- the acquisition of Enogex on May 1, 2013, which added $186 million in gross margin and $70 million in operation and maintenance and general and administrative expenses during the year ended December 31, 2014; and
- excluding the acquisition of Enogex:
- higher Gathering and Processing gross margin of $32 million;
- higher Transportation and Storage gross margin of $59 million; and
- higher payroll related expenses of $29 million and higher non-capital costs of $16 million, offset by lower integration costs of $9 million and other costs of $8 million, all within operation and maintenance and general and administrative expenses.

Investing Activities

The increase of $131 million, or 16%, in net cash used in investing activities for the year ended December 31, 2015 as compared to the year ended December 31, 2014 was primarily due to higher capital expenditures of $117 million, including the $80 million associated with the acquisition of the Monarch gas gathering system.

The increase of $675 million, or 482%, in net cash used in investing activities for the year ended December 31, 2014 as compared to the year ended December 31, 2013 was primarily due to:

- higher gathering and processing capital expenditures of $299 million;
- the payment of $434 million on notes receivable-affiliated companies in 2013;
- investment in equity method affiliates of $189 million;

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- lower transportation and storage capital expenditures of $45 million; and
- distributions from equity method affiliates of $198 million in 2014.

Financing Activities

Net cash used in financing activities decreased $262 million for the year ended December 31, 2015 as compared to the year ended December 31, 2014. Net cash used in financing activities decreased $350 million for the year ended December 31, 2014 as compared to the year ended December 31, 2013. Our primary financing activities consist of the following:

	Year Ended December 31,		
	2015	2014	2013
	(In millions)		
Repayment of Term Loan Facilities	$—	$(1,050)	$—
Proceeds from Term Loan Facilities	450	—	1,046
Repayment of EOIT Term Loan	—	(250)	—
Repayment of EOIT Senior Note	—	(200)	—
Proceeds from Enable Midstream Partners, LP 2019, 2024 and 2044 Notes, net of issuance costs	—	1,635	—
Net (repayments) proceeds of Revolving Credit Facility	310	(373)	372
Proceeds (repayments) from commercial paper program	(17)	253	—
Repayments of Notes Payable to Affiliates	—	—	(1,678)
Capital contributions from partners	—	464	43
Distributions to partners	(531)	(529)	(183)

Sources of Liquidity

As of December 31, 2015, our sources of liquidity included:
- cash on hand;
- cash generated from operations;
- proceeds of commercial paper issuances and borrowings under our Revolving Credit facility; and
- capital raised through debt and equity markets

Term Loan Facilities

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

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

On May 1, 2013, the Partnership entered into a $1.05 billion, three-year senior unsecured term loan facility (2013 Term Loan Facility), the proceeds of which were used to repay $1.05 billion of intercompany indebtedness owed to CenterPoint Energy. A wholly owned subsidiary of CenterPoint Energy had guaranteed collection of the Partnership's obligations under the 2013 Term Loan Facility, which guarantee was subordinated to all senior debt of such wholly owned subsidiary of CenterPoint Energy. Certain of the proceeds from the issuance of the 2019 Notes and 2024 Notes were used to repay the 2013 Term Loan Facility.

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Revolving Credit Facility

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

The Revolving Credit Facility permits outstanding borrowings to bear interest at the LIBOR and/or an alternate base rate, at the Partnership's election, plus an applicable margin. The applicable margin is based on the Partnership's applicable credit ratings. As of December 31, 2015, the applicable margin for LIBOR-based borrowings under the Revolving Credit Facility was 1.50% based on the Partnership's credit ratings. In addition, the Revolving Credit Facility requires the Partnership to pay a fee on unused commitments. The commitment fee is based on the Partnership's applicable credit rating from the rating agencies. As of December 31, 2015, the commitment fee under the Revolving Credit Facility was 0.20% per annum based on the Partnership's credit ratings. The commitment fee is recorded as interest expense in the Partnership's Combined and Consolidated Statements of Income.

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

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

Commercial Paper Program

We have a commercial paper program pursuant to which we are authorized to issue up to $1.4 billion of commercial paper. The commercial paper program is supported by our Revolving Credit Facility, and outstanding commercial paper effectively reduces our borrowing capacity thereunder. There was $236 million and $253 million outstanding under our commercial paper program as of December 31, 2015 and 2014, respectively. As of January 31, 2016, $232 million was outstanding under our commercial paper program. The weighted average interest rate for the outstanding commercial paper was 1.63% as of December 31, 2015. Our ability to access the commercial paper markets is dependent on our credit ratings. On February 2, 2016, Standard & Poor's Ratings Services lowered its credit rating on the Partnership from an investment grade rating to a non-investment grade rating. The short-term rating on the Partnership was also reduced from an investment grade rating to a non-investment grade rating. As a result, we expect our access to our commercial paper program to be limited until these ratings improve.

Promissory Notes Payable to Sponsor

Certain of the entities contributed to us by CenterPoint Energy on May 1, 2013 were obligated on $363 million of indebtedness owed to a wholly owned subsidiary of CenterPoint Energy. As of December 31, 2015, the $363 million notes payable—affiliated companies bear an annual interest rate of 2.10% to 2.45% and are scheduled to mature in 2017. The Partnership intends to redeem these notes in connection with the closing of the Private Placement. For a further discussion regarding the Private Placement, see "Equity Issuances" below.

Partnership Senior Notes

On May 27, 2014, the Partnership completed the private offering of $500 million 2.400% senior notes due 2019 (2019 Notes), $600 million 3.900% senior notes due 2024 (2024 Notes) and $550 million 5.000% senior notes due 2044 (2044 Notes), with registration rights. The Partnership received aggregate proceeds of $1.63 billion. Certain of the proceeds were used to repay

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the $1.05 billion senior unsecured 2013 Term Loan Facility, and certain of the proceeds were used to repay the EOIT $250 million variable rate term loan and the EOIT $200 million 6.875% senior notes due July 15, 2014, and for general corporate purposes. On July 15, 2014, the Partnership repaid the EOIT $200 million 6.875% senior notes. A wholly owned subsidiary of CenterPoint Energy has guaranteed collection of the Partnership’s obligations under the 2019 Notes and 2024 Notes, on an unsecured subordinated basis, subject to automatic release on May 1, 2016.

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

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

EOIT Senior Notes

As of December 31, 2015, the Partnership’s debt included EOIT’s $250 million 6.25% senior notes due March 2020 (the EOIT Senior Notes).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.

Equity Issuances

On April 16, 2014, the Partnership completed the Offering of 25,000,000 common units, representing limited partner interests in the Partnership, at a price to the public of $20.00 per common unit. The Partnership received net proceeds of $464 million. The Partnership retained the net proceeds of the Offering for general partnership purposes, including the funding of expansion capital expenditures, and to pre-fund demand fees expected to be incurred over the next three years relating to certain expiring transportation and storage contracts.

On January 28, 2016, the Partnership entered into an agreement (Purchase Agreement) with CenterPoint Energy to issue and sell in a Private Placement an aggregate of 14,520,000 Preferred Units for a cash purchase price of $25.00 per Preferred Unit, resulting in total gross proceeds of $363 million. The closing of the Private Placement, which is expected to occur prior to the end of the first quarter of 2016, is subject to the completion of due diligence by CenterPoint Energy, including the review of the Partnership’s audited financial statements and this Form 10-K, and certain customary closing conditions. In connection with the Private Placement, the Partnership intends to redeem the $363 million of Notes payable—affiliated companies scheduled to mature in 2017 payable to a subsidiary of CenterPoint Energy.

Pursuant to the Purchase Agreement, in connection with the closing of the Private Placement, Enable GP will execute a Third Amended and Restated Agreement of Limited Partnership of the Partnership (Amended Partnership Agreement) to, among other things, authorize and establish the terms of the Preferred Units and the other series of preferred units that are issuable upon conversion of the Preferred Units, in the form attached as an exhibit to the Purchase Agreement. Also, the Partnership has agreed to enter into a Registration Rights Agreement with CenterPoint Energy at the closing of the Private Placement, pursuant to which, among other things, the Partnership will give CenterPoint Energy certain rights to require the Partnership to file and maintain a registration statement with respect to the resale of the Preferred Units and any other series of preferred units or common units representing limited partnership interests in the Partnership that are issuable upon conversion of the Preferred Units.

The Preferred Units will 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. The Preferred Units have no stated maturity and 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.

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Holders of the Preferred Units will receive, on a non-cumulative basis and if and when declared by Enable GP, a quarterly cash distribution, subject to certain adjustments, equal to (x) from the date of original issue to, but not including, the five year anniversary of the original issue date, an annual rate of 10% on the stated liquidation preference and (y) thereafter, an annual rate of LIBOR plus a spread of 850 bps on the stated liquidation preference. At any time on or after five years after the original issue date, the Partnership may redeem the Preferred Units, in whole or in part, from any source of funds legally available for such purpose, by paying $25.50 per unit plus an amount equal to all accumulated and unpaid distributions thereon to the date of redemption, whether or not declared. In addition, the Partnership (or a third-party with its prior written consent) may redeem the Preferred Units following certain changes in the methodology employed by ratings agencies, changes of control or fundamental transactions as set forth in the Amended Partnership Agreement. If, upon a change of control or certain fundamental transactions, the Partnership (or a third-party with its prior written consent) does not exercise this option, then the holders of the Preferred Units have the option to convert the Preferred Units into a number of common units per Preferred Unit as set forth in the Amended Partnership Agreement. The Preferred Units are also required to be redeemed in certain circumstances if they are not eligible for trading on the NYSE.

Holders of Preferred Units will 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 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 Preferred Unit to a non-affiliate of CenterPoint Energy, the Preferred Units will automatically convert into a new series of preferred units (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 Preferred Units except that unpaid distributions on the Series B Preferred Units will accrue on a cumulative basis until paid.

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, 2016, we estimate that expansion capital will be approximately $375 million and our maintenance capital could range from approximately $105 million to $125 million. Our future expansion capital expenditures may vary significantly from period to period based on commodity prices and the investment opportunities available to us. We expect to fund future capital expenditures from cash flow generated from our operations, borrowings under our Revolving Credit Facility, the issuance of commercial paper or new debt offerings or the issuance of additional partnership units. Issuances of equity or debt in the capital markets and the issuance of commercial paper may not, however, be available to us on acceptable terms.

Distributions

We intend to pay a minimum quarterly distribution of $0.2875 per unit per quarter. We do not have a legal obligation to pay this distribution.

In determining the amount of distributable cash flow, 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 distributable cash flow 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 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

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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 under the Second Amended and Restated Agreement of Limited Partnership during the years ended December 31, 2015 and 2014 (in millions, except for per unit amounts):

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

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

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

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, 2015 and our best estimate of the period in which the obligation will be settled:

	2016	2017-2018	2019-2020	After 2020	Total
Maturities of short-term debt	$236	$—	$—	$—	$236
Maturities of long-term debt(1)(2)	—	450	1,060	1,150	2,660
Notes payable—affiliated companies(3)	—	363	—	—	363
Noncancellable operating leases	14	8	1	—	23
Other purchase obligations and commitments	1	—	—	—	1
Total contractual obligations	$251	$821	$1,061	$1,150	$3,283

(1) Estimated contractual interest payments associated with long-term debt are $79 million, $157 million, $131 million and $728 million in 2016, 2017 through 2018, 2019 through 2020 and after 2020, respectively. The Revolving Credit Facility estimated contractual interest payments are calculated utilizing the respective variable interest rates as of December 31, 2015.

(2) Excludes premium on EOIT Senior Notes of $23 million.

(3) Estimated contractual interest payments associated with notes payable-affiliated companies are $8 million, $8 million, $-0- and $-0- in 2016, 2017 through 2018, 2019 through 2020 and after 2020, respectively. The Partnership intends to redeem these notes in connection with the closing of the Private Placement. For a further discussion regarding the Private Placement, see Item 7. “Management’s Discussion and Analysis of Financial Condition and Results of Operation —Liquidity and Capital Resources—Equity Issuances.”

Customer Concentration

We rely on certain key natural gas producer customers for a significant portion of our natural gas and NGLs supply. For the year ended December 31, 2015, our top ten natural gas producer customers accounted for approximately 65% of our gathered volumes. These customers include affiliates of Continental, XTO, Vine, Chesapeake, GeoSouthern, Apache, Covey Park, Devon, Tapstone and BP.

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We rely on certain key utilities for a significant portion of our transportation and storage demand. For the year ended December 31, 2015, our top transportation and storage customers by gross margin were affiliates of CenterPoint Energy, Laclede, XTO, OGE Energy, AEP, Chesapeake, EOG, Midcontinent, Entergy and Continental.

Off-Balance Sheet Arrangements

We do not have any off-balance sheet arrangements.

Credit Risk

We are exposed to certain credit risks relating to our ongoing business operations. Credit risk includes the risk that counterparties that owe us money or energy will breach their obligations. If the counterparties to these arrangements fail to perform, we may be forced to enter into alternative arrangements. In that event, our financial results could be adversely affected, and we could incur losses. We examine the creditworthiness of third party customers to whom we extend credit and manage our exposure to credit risk through credit analysis, credit approval, credit limits and monitoring procedures, and for certain transactions, we may request letters of credit, prepayments or guarantees, or seek to renegotiate our contract to reduce credit exposure.

Impact of Seasonality

While the results of our gathering and processing segment are not materially affected by seasonality, from time to time our operations can be impacted by inclement weather. Our transportation and storage segment experiences seasonal impacts associated with storage spreads, basis spreads on market-based pipelines, power plant demand and local distribution company customer demand.

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, valuation of revenues, natural gas purchases, valuation of assets, depreciable lives of property, plant and equipment and amortization methodologies related to intangible assets and commitments and contingencies. 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 Combined and Consolidated Financial Statements.

Impairment of Long-lived Assets (including Intangible Assets)

The Partnership periodically evaluates long-lived assets, including property, plant and equipment, and specifically identifiable intangibles other than goodwill, when events or changes in circumstances indicate that the carrying value of these assets may not be recoverable. The determination of whether an impairment has occurred is based on an estimate of undiscounted cash flows attributable to the assets, as compared to the carrying value of the assets. During the years ended December 31, 2015, 2014 and 2013, the Partnership recorded impairments of $10 million, $7 million and $12 million, respectively, on the Service Star business line, a component of our gathering and processing segment. During the year ended December 31, 2015, in connection with the preparation of the financial statements, the Partnership recorded a $25 million impairment on the Atoka assets in our gathering and processing segment and a $12 million impairment on jurisdictional pipelines in our transportation and storage segment. The Partnership recorded no other material impairments to long-lived assets in the years ended December 31, 2015, 2014 or 2013. Based upon review of forecasted undiscounted cash flows, none of the asset groups were at risk of failing step one of the impairment test. Further price declines, throughput declines, cost increases, regulatory or political environment changes, and other changes in market conditions could reduce forecast undiscounted cash flows.

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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 tested its goodwill for impairment on May 1, 2013 upon formation and following formation tests annually on October 1. The Partnership utilizes the market or income approaches to estimate the fair value of the reporting unit, also giving consideration to the alternative cost approach. Under the market approach, historical and current year forecasted cash flows are multiplied by a market multiple to determine fair value. Under the income approach, anticipated cash flows over a period of years plus a terminal value are discounted to present value using appropriate discount rates. If the estimated fair value of the reporting unit is less than the carrying amount of the reporting unit, then a second step must be completed in order to determine the amount of the goodwill impairment that should be recorded. In the second step, the implied fair value of the reporting unit's goodwill is determined by allocating the reporting unit's fair value to all of its assets and liabilities other than goodwill (including any unrecognized intangible assets) in a manner similar to a purchase price allocation. The resulting implied fair value of the goodwill that results from the application of this second step is then compared to the carrying amount of the goodwill and an impairment charge is recorded for the difference. The Partnership performs its goodwill impairment testing one level below the Transportation and Storage and Gathering and Processing segment level at the operating segment level.

Because quoted market prices for the Partnership's reporting units are not available, management must apply judgment in determining the estimated fair value of reporting units for purposes of performing the goodwill impairment test, when necessary. Management considered observable transactions in the market, as well as trading multiples and cost of capital for peers, to determine appropriate multiples and discount rates to apply against historical and forecasted cash flows. A lower fair value estimate in the future for any of the Partnership's reporting units could result in a goodwill impairment. Factors that could trigger a lower fair value estimate include sustained price declines, throughput declines, 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 Partnership performed the first step of our annual goodwill impairment analysis as of October 1, 2015, and determined that the carrying value of the gathering and processing and transportation and storage reportable segments exceeded fair value. The Partnership completed the second step of the goodwill impairment analysis by comparing the implied fair value of the reporting unit to the carrying amount of that goodwill and determined that goodwill was completely impaired in the amount of $1,087 million, which is included in Impairments on the Combined and Consolidated Statements of Income for the year ended December 31, 2015. As of December 31, 2015, the Partnership has no goodwill recognized 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 gathering. The Partnership performs these services under various contractual arrangements, which include fee-based contract arrangements and arrangements pursuant to which it purchases and resells commodities in connection with providing the related service and earns a net margin for its fee. While the Partnership's transactions vary in form, the essential element of each transaction is the use of its assets to transport a product or provide a processed product to a customer. The Partnership reflects revenue as Product sales and Service revenue on the Combined and Consolidated Statements of Income as follows:

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

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

Revenues for gathering, processing, transportation and storage services for the Partnership are recorded each month based on the current month's estimated volumes, contracted prices (considering current commodity prices), historical seasonal fluctuations and any known adjustments. The estimates are reversed in the following month and customers are billed on actual volumes and contracted prices. Gas sales are calculated on current-month nominations and contracted prices. Revenues associated with the production of NGLs are estimated based on current-month estimated production and contracted prices. These amounts are reversed in the following month and the customers are billed on actual production and contracted prices. Estimated revenues are reflected in Accounts Receivable or Accounts Receivable-affiliated companies, as appropriate, on the Consolidated Balance Sheets and in Revenues on the Combined and Consolidated Statements of Income.

The Partnership recognizes revenue from natural gas gathering, processing, transportation and storage and crude oil gathering

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services to third parties as services are provided. Revenue associated with NGLs is recognized when the production is sold. The Partnership records deferred revenue when it receives consideration from a third party before achieving certain criteria that must be met for revenue to be recognized in accordance with GAAP. The Partnership has $17 million and $18 million of deferred revenues on the Consolidated Balance Sheets at December 31, 2015 and 2014, respectively.

Valuation of Assets

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

In the years ended December 31, 2015 and 2013, the Partnership completed acquisitions accounted for as business combinations as discussed in Note 3 of the Notes to Combined and Consolidated Financial Statements. As part of these acquisitions, the Partnership has engaged the services of third-party valuation experts 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.

Supplemental Disclosures

Certain information contained in this report relates to periods that began prior to the acquisition of Enogex by Enable Midstream Partners, LP. The Partnership believes that combined historical data with Enogex, along with certain pro forma adjustments, is relevant and meaningful, enhances the discussion of periods presented and is useful to the reader to better understand trends in the Partnership's operations. The pro forma adjustments, as discussed in the unaudited supplemental pro forma Combined Statement of Income below, only give effect to events that are (1) directly attributable to the formation of the Partnership; (2) factually supportable; and (3) expected to have a continuing effect on the consolidated results of the Partnership.

The following information is for informational purposes only and should not be considered indicative of future results. The following pro forma financial data was derived from the Partnership's combined financial information, Enogex consolidated financial information and certain adjustments described below. Further, management does not believe that the pro forma financial data is necessarily indicative of the financial data that would have been reported by the Partnership had the acquisition of Enogex closed prior to the historical period presented, future results of the Partnership, or other transactions that resulted in the formation of the Partnership.

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Results of Operations—Pro Forma

The following table provides a summary of our results of operations on a historical basis for the year ended December 31, 2014 compared to our results of operations on a pro forma basis for the year ended December 31, 2013.

Historical Year Ended December 31, 2014	Gathering and Processing	Transportation and Storage	Eliminations	Enable Midstream Partners, LP
	(In millions)			
Revenues	$2,424	$1,577	$(634)	$3,367
Cost of natural gas and natural gas liquids, excluding depreciation and amortization	1,585	961	(632)	1,914
Gross margin on revenues	839	616	(2)	1,453
Operation and maintenance, General and administrative	297	232	(2)	527
Depreciation and amortization	160	116	—	276
Impairments	8	—	—	8
Taxes other than income tax	25	31	—	56
Operating income	$349	$237	$—	$586
Equity in earnings of equity method affiliates	$—	$20	$—	$20

Pro forma Year Ended December 31, 2013	Gathering and Processing	Transportation and Storage	Eliminations	Enable Midstream Partners, LP
	(In millions)			
Revenues	$2,209	$1,447	$(536)	$3,120
Cost of natural gas and natural gas liquids, excluding depreciation and amortization	1,447	885	(534)	1,798
Gross margin on revenues	762	562	(2)	1,322
Operation and maintenance, General and administrative	269	226	(2)	493
Depreciation and amortization	162	107	—	269
Impairments	12	—	—	12
Taxes other than income tax	24	38	—	62
Operating income	$295	$191	$—	$486
Equity in earnings of equity method affiliates	$—	$12	$—	$12

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	Year Ended December 31,	
	Historical	Pro Forma
	2014	2013
Operating Data:		
Gathered volumes—TBtu	1,221	1,298
Gathered volumes—TBtu/d	3.34	3.56
Natural gas processed volumes—TBtu	569	524
Natural gas processed volumes—TBtu/d	1.56	1.44
NGLs produced - MBbl/d[(1)]	66.74	59.45
NGLs sold - MBbl/d[(1)(3)]	68.67	59.82
Condensate sold - MBbl/d	4.38	2.96
Crude Oil - Gathered volumes - MBbl/d[(2)]	3.64	—
Transported volumes—TBtu	1,808	1,803
Transportation volumes—TBtu/d	4.95	4.94
Interstate firm contracted capacity—Bcf/d	7.73	8.01
Intrastate Transported volumes - TBtu/d	1.61	1.59

(1) Excludes condensate.
(2) Initial operation of our crude oil gathering system began on November 1, 2013.
(3) NGLs sold includes volumes of NGLs withdrawn from inventory or purchased for system balancing purposes.

Gathering and Processing

2014 compared to 2013. Our gathering and processing segment reported operating income of $349 million in the year ended December 31, 2014 compared to pro forma operating income of $295 million in the year ended December 31, 2013. Operating income increased $54 million primarily from an increase in gross margin of $77 million, a decrease in impairments of $4 million and a decrease in depreciation and amortization of $2 million, partially offset by an increase in operation and maintenance and general and administrative expenses of $28 million and an increase in taxes other than income tax of $1 million, during the year ended December 31, 2014.

Our gathering and processing segment gross margin increased $77 million primarily due to higher average natural gas prices of $9 million, higher processing margin of $65 million due to higher processed volumes in the Anadarko and Ark-La-Tex basins, unrealized gains on condensate derivatives of $5 million, and the addition of gross margin on our crude oil gathering business of $5 million, partially offset by $7 million of higher cost of goods sold on third party measurement and communication services and decreased gathered volumes in the Ark-La-Tex and Arkoma basins, offset by minimum volume payments.

Our gathering and processing segment operation and maintenance and general and administrative expenses increased $28 million primarily due to an increase in payroll-related expenses of $6 million to support business growth, an increase in integration costs of $6 million, an increase in general operating and maintenance expenses of $15 million to support and operate new assets, a write down of materials and supplies inventory of $4 million and a loss on sale of assets of $1 million, partially offset by $4 million due to lower third party measurement and communications services.

Our gathering and processing segment depreciation and amortization expense decreased $2 million due to decreased depreciation expense of $4 million from the implementation of new rates from a 2013 depreciation study on the assets acquired with Enogex, partially offset by assets placed in service of $2 million.

Our gathering and processing segment recognized impairments of $8 million and $12 million in 2014 and 2013, respectively. Due to the cancellation of services by additional customers during 2014, management reassessed the carrying value of the Service Star business line which resulted in the 2014 impairment. Therefore the $4 million increase was primarily due to the decrease in the Service Star impairment of $5 million, offset by additional impairments of other assets of $1 million in 2014.

Our gathering and processing segment taxes other than income tax increased $1 million due to increased ad valorem taxes as a result of additional assets in service of $4 million, partially offset by the favorable settlement of a state and local tax dispute for $3 million less than the previously recognized reserve.

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Transportation and Storage

2014 compared to 2013. Our transportation and storage segment reported operating income of $237 million in the year ended December 31, 2014 compared to pro forma operating income of $191 million in the year ended December 31, 2013 . Operating income increased $46 million primarily resulting from an increase in gross margin of $54 million and a decrease in taxes other than income tax of $7 million, partially offset by an increase of $6 million in operation and maintenance and general and administrative expenses, as well as an increase of $9 million in depreciation and amortization, during the year ended December 31, 2014.

Our transportation and storage segment gross margin increased $54 million primarily due to an increase in unrealized gains on natural gas derivatives of $32 million, an increase from system optimization opportunities of $10 million, an increase from operational synergies of $3 million, an increase from off-system transportation revenues of $6 million, higher rates on transportation services for local distribution companies of $9 million, and higher other firm transportation revenues of $4 million, partially offset by a decrease in storage demand fees of $9 million and balancing services of $1 million.

Our transportation and storage segment operation and maintenance and general and administrative expenses increased $6 million due to an increase in payroll-related expense of $25 million from increased head count to support business growth, an increase in general operating and maintenance expenses of $5 million, and a write down of materials and supplies inventory of $2 million, partially offset by a decrease in relocation costs of $4 million, a decrease in allocated corporate service costs of $15 million, and a litigation settlement of $5 million in 2013, offset in 2014 by $2 million of insurance proceeds.

Our transportation and storage segment depreciation and amortization increased $9 million primarily due increased depreciation expense of $4 million from the implementation of new rates from a 2013 depreciation study, MRT rate case impact of $1 million and asset additions of $4 million.

Our transportation and storage segment taxes other than income tax decreased $7 million due to reduced ad valorem taxes.

Equity Earnings. Our transportation and storage segment recorded equity in earnings of equity method affiliates of $20 million and pro forma equity in earnings of equity method affiliates of $12 million for the years ended December 31, 2014 and 2013, respectively, from our interest in SESH. The 2014 increase in equity earnings compared to pro forma equity in earnings for 2013 is attributable to the 24.95% interest in SESH contributed by CenterPoint Energy on May 30, 2014 to the Partnership.

Consolidated Historical Information and Combined Pro Forma Information

	Year Ended December 31,	
	Historical 2014	Pro Forma 2013
	(In millions)	
Operating Income	$586	$486
Other Income (Expense):		
Interest expense	(70)	(49)
Equity in earnings of equity method affiliates	20	12
Interest income—affiliated companies	—	—
Other, net	(1)	9

Total Other Income (Expense)	(51)	(28)
Income Before Income Taxes	535	458
Income tax expense (benefit)	2	4
Net Income	$533	$454
Less: Net income attributable to noncontrolling interest	3	3
Net Income attributable to Enable Midstream Partners, LP	$530	$451

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UNAUDITED SUPPLEMENTAL PRO FORMA COMBINED STATEMENT OF INCOME
For the year ended December 31, 2013

	Enable Midstream Partners, LP Historical	Enogex Historical	Pro Forma Adjustments		Pro Forma
	(In millions)				
Revenues	$2,489	$630	$1	A	$3,120
Cost of natural gas and natural gas liquids, excluding depreciation and amortization	1,313	489	(4)	A	1,798
Operating Expenses:					
Operation and maintenance, General and administrative	429	64	—		493
Depreciation and amortization	212	37	20	A	269
Impairment	12	—	—		12
Taxes other than income tax	54	8	—		62
Total Operating Expenses	707	109	20		836
Operating income	469	32	(15)		486
Other Income (Expense):					
Interest expense	(67)	(10)	31	B	(49)
			2	B	
			(7)	C	
			(1)	D	
			3	A	
Equity in earnings of equity method affiliates	15	—	(3)	F	12
Interest income—affiliated companies	9	—	(9)	B	—
Other, net	—	9	—		9
Total Other Income (Expense)	(43)	(1)	16		(28)
Income Before Income Taxes	426	31	1		458
Income tax expense (benefit)	(1,192)	—	1,196	E	4
Net Income	$1,618	$31	$(1,195)		$454
Less: Net income attributable to noncontrolling interest	3	—	—		3
Net Income attributable to Enable Midstream Partners, LP	$1,615	$31	$(1,195)		$451

(A) This adjustment reflects the acquisition of Enogex on May 1, 2013:
Revenue. The impact of removing the historical amortization and the historical recognition of deferred revenues at May 1, 2013 results in a net increase to revenue of $1 million during the year ended December 31, 2013.
Cost of natural gas and natural gas liquids, excluding depreciation and amortization. The impact of recognizing liabilities for Enogex loss contracts at May 1, 2013 results in a reduction to cost of natural gas and natural gas liquids, excluding depreciation and amortization, of $4 million during the year ended December 31, 2013.
Depreciation and Amortization. As a result of applying purchase accounting to the acquisition of Enogex, property, plant and equipment and identifiable intangible assets were recorded at their fair value, resulting in additional depreciation and amortization expense. The impact of the step-up on depreciation expense is $20 million during the year ended December 31, 2013.

Interest Expense. The pro forma impact of the amortization of the premium, less the historical recognition of the premium, discount and deferred charges on interest expense, net of historical capitalized interest, is $3 million during the year ended December 31, 2013.

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(B) Interest Expense. This adjustment reflects the settlement on May 1, 2013 of certain notes receivable—affiliated companies and notes payable—affiliated companies with CenterPoint Energy and OGE Energy, historically held by the Partnership and Enogex, respectively, decreasing interest expense by a total of $24 million during the year ended December 31, 2013.

(C) Interest Expense. This adjustment reflects the entrance into the $1.05 billion 2013 Term Loan Facility on May 1, 2013: this issuance results in an increase in interest expense of $7 million during the year ended December 31, 2013.

(D) Interest Expense. This adjustment reflects the entrance into the Revolving Credit Facility on May 1, 2013: this issuance results in an increase in interest expense of $1 million during the year ended December 31, 2013.

(E) Income Tax Expense. Upon conversion to a limited partnership on May 1, 2013, the Partnership's earnings are no longer subject to income tax (other than Texas state margin taxes) and are taxable at the individual partner level. The pro forma adjustment to income taxes for the year ended December 31, 2013 removes $1.24 billion of historical income tax expense.

(F) Equity in earnings of equity method affiliates. The 25.05% interest in SESH distributed to CenterPoint Energy results in a pro forma reduction to earnings of equity method affiliates of $3 million during the year ended December 31, 2013.

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Pro forma Non-GAAP Financial Measures

	Year Ended December 31,	
	Historical 2014	Pro Forma 2013
	(In millions)	
Reconciliation of Gross Margin to Revenues:		
Revenues	$3,367	$3,120
Cost of natural gas and natural gas liquids, excluding depreciation and amortization	1,914	1,798
Gross margin	$1,453	$1,322
Reconciliation of Adjusted EBITDA and distributable cash flow to net income attributable to controlling interest:		
Net income attributable to Enable Midstream Partners, LP	$530	$451
Add:		
Depreciation and amortization expense	276	269
Interest expense, net of interest income	70	49
Income tax expense (benefit)	2	4
EBITDA	$878	$773
Add:		
Loss on extinguishment of debt	4	—
Distributions from equity method affiliates(1)	23	16
Non-cash equity based compensation (2)	13	—
Other non-cash losses	22	—
Impairment	8	12
Less:		
Other non-cash gains	(46)	—
Noncontrolling Interest Share of Adjusted EBITDA	(1)	—
Equity in earnings of equity method affiliates	(20)	(12)
Gain on disposition	—	(10)
Adjusted EBITDA	$881	$779
Less:		
Adjusted interest expense, net (3)	(82)	(61)
Maintenance capital expenditures	(164)	(174)
Current income taxes(4)	(1)	(2)
Distributable cash flow	$634	$542

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

(2) In the fourth quarter of 2015, the calculation of Adjusted EBITDA was modified to account for non-cash equity based compensation expense to be consistent with industry peers.

(3) Adjusted interest expense, net excludes the effect of the amortization of the premium on EOIT's fixed rate senior notes. This exclusion is the primary reason for the difference between "Interest expense, net" and "Adjusted interest expense, net."

(4) In the second quarter of 2015, the calculation of Distributable cash flow was modified to account for current income tax expense to be consistent with industry peers.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

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

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Commodity Price Risk

While we generate a substantial portion of our gross margin pursuant to long-term, fee-based contracts that include minimum volume commitments and/or demand fees, we are also exposed to changes in the prices of natural gas 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.

Based on our forecasted volumes, prices and contractual arrangements, we estimate approximately 14%, of our total gross margin for the twelve months ending December 31, 2016 is directly exposed to changes in commodity prices, excluding the impact of hedges and contractual floors related to certain agreements. Since December 31, 2015, we have entered into additional derivative contracts to further manage our exposure to commodity price risk for the twelve months ending December 31, 2016.

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 $7 million for natural gas and $7 million for condensate and NGLs, excluding the impact of hedges, for the twelve months ending December 31, 2016.

Interest Rate Risk

Our current interest rate risk exposure is related primarily to our debt portfolio. Our debt portfolio is primarily comprised of fixed rate debt, which mitigates the impact of fluctuations in interest rates. Future issuances of long-term debt could be impacted by increases in interest rates, which could result in higher interest costs. Any borrowings under our Revolving Credit Facility and any issuances under our commercial paper program could be at a variable interest rate and could expose us to the risk of increasing interest rates. Based upon the $996 million outstanding borrowings under the 2015 Term Loan Facility, Revolving Credit Facility and our commercial paper program as of December 31, 2015, 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.

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

We have audited the accompanying consolidated balance sheets of Enable Midstream Partners, LP and subsidiaries (the "Partnership") as of December 31, 2015 and 2014, and the related combined and consolidated statements of income, comprehensive income, cash flows, and parent net equity and partners’ capital for each of the three years in the period ended December 31, 2015. These financial statements are the responsibility of the Partnership's management. Our responsibility is to express an opinion on the financial statements based on our audits.

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

In our opinion, such combined and consolidated financial statements present fairly, in all material respects, the financial position of Enable Midstream Partners, LP and subsidiaries as of December 31, 2015 and 2014, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2015, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 1 to the combined and consolidated financial statements, the combined and consolidated financial statements have been prepared from the historical accounting records maintained by CenterPoint Energy, Inc. and its subsidiaries for the Partnership until May 1, 2013 and may not necessarily be indicative of the financial position, results of operations and cash flows that would have existed had the Partnership operated as a separate and unaffiliated company until the Partnership formation on

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May 1, 2013. All of the Partnership’s combined entities were under common control and management for the periods presented until May 1, 2013. Beginning on May 1, 2013, the Partnership consolidated Enogex LLC and all previously combined entities.

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

/s/ DELOITTE & TOUCHE LLP

Houston, Texas
February 17, 2016

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have audited the internal control over financial reporting of Enable Midstream Partners, LP and subsidiaries (the "Partnership") as of December 31, 2015, based on criteria established in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Partnership's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management’s Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the Partnership's internal control over financial reporting based on our audit.

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

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

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the Partnership maintained, in all material respects, effective internal control over financial reporting as of December 31, 2015, based on the criteria established in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission.

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

/s/ DELOITTE & TOUCHE LLP

Houston, Texas
February 17, 2016

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ENABLE MIDSTREAM PARTNERS, LP
COMBINED AND CONSOLIDATED STATEMENTS OF INCOME

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

See Notes to the Combined and Consolidated Financial Statements

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

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

See Notes to the Combined and Consolidated Financial Statements

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ENABLE MIDSTREAM PARTNERS, LP
CONSOLIDATED BALANCE SHEETS

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

Total Liabilities and Partners’ Capital	$11,238	$11,837

See Notes to the Combined and Consolidated Financial Statements

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

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

Net cash provided by (used in) financing activities	212	(50)	(400)
Net Increase (Decrease) in Cash and Cash Equivalents	(8)	(96)	108
Cash and Cash Equivalents at Beginning of Period	12	108	—
Cash and Cash Equivalents at End of Period	$4	$12	$108

See Notes to the Combined and Consolidated Financial Statements
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ENABLE MIDSTREAM PARTNERS, LP
COMBINED AND CONSOLIDATED STATEMENTS OF
ENABLE MIDSTREAM PARTNERS, LP PARENT NET EQUITY AND PARTNERS' CAPITAL

	Partners' Capital								
	Common Units		Subordinated Units		Parent Net Investment	Accumulated Other Comprehensive Loss	Total Enable Midstream Partners, LP Partners' Capital	Noncontrolling Interest	Total Partners' Capital
	Units	Value	Units	Value	Value	Value	Value	Value	Value
	(In millions)								
Balance as of December 31, 2012	—	$—	—	$—	$3,221	$ (6)	$ 3,215	$ 6	$3,221
Net income	—	—	—	—	1,326	—	1,326	—	1,326
Contributions from (Distributions to) CenterPoint Energy prior to formation (Note 5)	—	—	—	—	(295)	6	(289)	—	(289)
Balance as of April 30, 2013	—	$—	—	$—	$4,252	$ —	$ 4,252	$ 6	$4,258
Conversion to a limited partnership	227	4,252	—	—	(4,252)	—	—	—	—
Issuance of units upon acquisition of Enogex on May 1, 2013	163	3,788	—	—	—	—	3,788	26	3,814
Net income	—	289	—	—	—	—	289	3	292
Distributions to partners	—	(181)	—	—	—	—	(181)	(2)	(183)
Balance as of December 31, 2013	390	$8,148	—	$—	$—	$ —	$ 8,148	$ 33	$8,181
Conversion to subordinated units	(208)	(4,372)	208	4,372	—	—	—	—	—
Net income	—	349	—	181	—	—	530	3	533
Issuance of Offering common units	25	464	—	—	—	—	464	—	464
Issuance of common units upon interest acquisition of SESH	6	161	—	—	—	—	161	—	161
Distributions to partners	—	(410)	—	(114)	—	—	(524)	(5)	(529)
Equity based compensation	1	13	—	—	—	—	13	$ —	13
Balance as of December 31, 2014	214	$4,353	208	$4,439	$—	$ —	$ 8,792	$ 31	$8,823
Net loss	—	(379)	—	(373)	—	—	(752)	(19)	(771)
Issuance of common units upon interest	—	1	—	—	—	—	1	—	1

acquisition of SESH									
Distributions to partners	—	(270)	—	(261)	—	—	(531)	—	(531)
Equity based compensation	—	9	—	—	—	—	9	—	$9
Balance as of December 31, 2015	214	$3,714	208	$3,805	$—	$—	$7,519	$12	$7,531

See Notes to the Combined and Consolidated Financial Statements

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

(1) Summary of Significant Accounting Policies

Organization

Enable Midstream Partners, LP (Partnership) is a Delaware limited partnership formed on May 1, 2013 by CenterPoint Energy, Inc. (CenterPoint Energy), OGE Energy Corp. (OGE Energy) and affiliates of ArcLight Capital Partners, LLC (ArcLight), pursuant to the terms of the MFA. The Partnership is a large-scale, growth-oriented limited partnership formed to own, operate and develop strategically located natural gas and crude oil infrastructure assets. The Partnership’s assets and operations are organized into two reportable segments: (i) Gathering and Processing, which primarily provides natural gas gathering, processing and fractionation services and crude oil gathering for our producer customers, and (ii) Transportation and Storage, which provides interstate and intrastate natural gas pipeline transportation and storage services primarily to natural gas producers, utilities and industrial customers. The natural gas gathering and processing assets are located in five states and serve natural gas production in the Anadarko, Arkoma and Ark-La-Tex basins. This segment also includes a crude oil gathering business in the Bakken Shale formation, principally located in the Williston basin. The natural gas transportation and storage assets extend from western Oklahoma and the Texas Panhandle to Alabama and from Louisiana to Illinois.

The Partnership is controlled equally by CenterPoint Energy and OGE Energy, who each have 50% of the management rights of Enable GP. Enable GP was established by CenterPoint Energy and OGE Energy to govern the Partnership and has no other operating activities. Enable GP is governed by a board made up of an equal number of representatives designated by each of CenterPoint Energy and OGE Energy, along with the Partnership's Chief Executive Officer and the independent board members CenterPoint Energy and OGE Energy mutually agreed to appoint. Based on the 50/50 management ownership, with neither company having control, effective May 1, 2013, CenterPoint Energy and OGE Energy deconsolidated their interests in the Partnership and Enogex, respectively. CenterPoint Energy and OGE Energy also own a 40% and 60% interest, respectively, in the incentive distribution rights held by Enable GP.

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

Upon conversion to a limited partnership on May 1, 2013, the Partnership’s earnings are generally no longer subject to income tax (other than Texas state margin taxes and taxes associated with the Partnership's corporate subsidiary, Enable Midstream Services) and are taxable at the individual partner level. As a result of the conversion to a partnership immediately prior to formation, CenterPoint Energy assumed all outstanding current income tax liabilities and the Partnership derecognized the deferred income tax assets and liabilities by recording an income tax benefit of $1.24 billion. Consequently, the Combined and Consolidated Statements of Income do not include an income tax provision on income earned on or after May 1, 2013 (other than Texas state margin taxes and taxes associated with the Partnership's corporate subsidiary, Enable Midstream Services). See Note 16 for further discussion of the Partnership’s income taxes.

Prior to May 1, 2013, the financial statements of the Partnership include EGT, MRT and the non-rate regulated natural gas gathering, processing and treating operations, which were under common control by CenterPoint Energy, and a 50% interest in SESH. Through the Partnership's formation on May 1, 2013, CenterPoint Energy retained certain assets and liabilities and related balances in accumulated other comprehensive loss, historically held by the Partnership, such as certain notes payable—affiliated companies to CenterPoint Energy and benefit plan obligations. Additionally, the Partnership distributed a 25.05% interest in SESH to CenterPoint Energy, subject to future acquisition by the Partnership through put and call options discussed in Note 9. On May 1, 2013, OGE Energy and ArcLight indirectly contributed 100% of the equity interests in Enogex to the Partnership in exchange for limited partner interests and, for OGE Energy only, interests in Enable GP. The Partnership concluded that the Partnership formation on May 1, 2013 was considered a business combination, and for accounting purposes, the Partnership was the acquirer of Enogex. Subsequent to May 1, 2013, the financial statements of the Partnership are consolidated to reflect the formation of the Partnership and the acquisition of Enogex. See Note 3 for further discussion of the acquisition of Enogex. For the period from May 1, 2013 through May 29, 2014, the financial statements reflect a 24.95% interest in SESH. For the period of May 30, 2014 through June 29, 2015, the financial statements reflect a 49.90% interest in SESH. On June 12, 2015, CenterPoint Energy exercised its put right with respect to a 0.1% interest in SESH. Pursuant to the put right, on June 30, 2015, CenterPoint Energy contributed

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its remaining 0.1% interest in SESH to the Partnership in exchange for 25,341 common units representing limited partner interests in the Partnership. As of December 31, 2015, the Partnership owned a 50% interest in SESH. See Note 9 for further discussion of SESH.

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

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

Basis of Presentation

The accompanying combined and consolidated financial statements and related notes of the Partnership have been prepared pursuant to the rules and regulations of the SEC and GAAP. For accounting and financial reporting purposes, (i) the formation of the Partnership is considered a contribution of real estate by CenterPoint Energy and is reflected at CenterPoint Energy’s historical cost as of May 1, 2013 and (ii) the Partnership acquired Enogex on May 1, 2013.

The combined and consolidated financial statements have been prepared from the historical accounting records maintained by CenterPoint Energy for the Partnership until May 1, 2013 and may not necessarily be indicative of the condition that would have existed or the results of operations if the Partnership had been operated as a separate and unaffiliated entity. All of the Partnership’s historical combined entities were under common control and management for the periods presented until May 1, 2013, and all intercompany transactions and balances are eliminated in combination and consolidation, as applicable. Beginning on May 1, 2013, the Partnership consolidated Enogex and all previously combined entities of the Partnership.

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

Use of Estimates

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, disclosure of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Revenue Recognition

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

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

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

Revenues for gathering, processing, transportation and storage services for the Partnership are recorded each month based on the current month's estimated volumes, contracted prices (considering current commodity prices), historical seasonal fluctuations and any known adjustments. The estimates are reversed in the following month and customers are billed on actual volumes and contracted prices. Gas sales are calculated on current-month nominations and contracted prices. Revenues associated with the production of NGLs are estimated based on current-month estimated production and contracted prices. These amounts are reversed in the following month and the customers are billed on actual production and contracted prices. Estimated revenues are reflected in Accounts Receivable or Accounts Receivable-affiliated companies, as appropriate, on the Consolidated Balance Sheets and in Revenues on the Combined and Consolidated Statements of Income.

The Partnership recognizes revenue from natural gas gathering, processing, transportation and storage and crude oil gathering services to third parties as services are provided. Revenue associated with NGLs is recognized when the production is sold. The Partnership records deferred revenue when it receives consideration from a third party before achieving certain criteria that must be met for revenue to be recognized in accordance with GAAP. The Partnership has $17 million and $18 million of deferred revenues on the Consolidated Balance Sheets at December 31, 2015 and 2014, respectively.

The Partnership relies on certain key natural gas producer customers for a significant portion of natural gas and NGLs supply. The Partnership relies on certain key utilities for a significant portion of transportation and storage demand. The Partnership depends on third-party facilities to transport and fractionate NGLs that it delivers to third parties at the inlet of their facilities. Additionally for the years ended December 31, 2015, 2014 and 2013, one third party purchased approximately 18%, 21% and 30%, respectively, of the NGLs delivered off our system, which accounted for approximately $108 million, $235 million and $232 million, or 4%, 7% and 9%, respectively, of total revenue. Other than revenues from affiliates discussed in Note 14, there are no other revenue concentrations with individual customers in the years ended December 31, 2015, 2014, and 2013.

Natural Gas and Natural Gas Liquids Purchases

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

Operation and Maintenance and General and Administrative Expense

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

Environmental Costs

The Partnership expenses or capitalizes environmental expenditures, as appropriate, depending on their future economic benefit. The Partnership expenses amounts that relate to an existing condition caused by past operations that do not have future economic benefit. The Partnership records undiscounted liabilities related to these future costs when environmental assessments and/or remediation activities are probable and the costs can be reasonably estimated. There are no material amounts accrued at December 31, 2015 or 2014.

Depreciation and Amortization Expense

Depreciation is computed using the straight-line method based on economic lives or a regulatory-mandated recovery period. Amortization of intangible assets is computed using the straight-line method over the respective lives of the intangible assets.

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

During 2013, the Partnership completed a depreciation study for the Gathering and Processing segment, as well as the acquired Enogex assets. The new depreciation rates have been applied prospectively. There were no material changes in weighted average useful lives for pre-acquisition Gathering and Processing assets.

Income Taxes

Prior to May 1, 2013, the Partnership was included in the consolidated income tax returns of CenterPoint Energy. The Partnership calculated its income tax provision on a separate return basis under a tax sharing agreement with CenterPoint Energy. The Partnership used the asset and liability method of accounting for deferred income taxes in accordance with accounting guidance for income taxes. Deferred income tax assets and liabilities were recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases. A valuation allowance was established against deferred tax assets for which management believed realization was not considered more likely than not. Current federal and certain state income taxes were payable to or receivable from CenterPoint Energy. The Partnership recognized interest and penalties as a component of income tax expense. Upon conversion to a limited partnership on May 1, 2013, the Partnership's earnings are no longer subject to income tax (other than Texas state margin taxes and taxes associated with the Partnership's corporate subsidiary, Enable Midstream Services) and are taxable at the individual partner level. For more information, see Note 16.

Cash and Cash Equivalents

The Partnership considers cash equivalents to be short-term, highly liquid investments with maturities of three months or less from the date of purchase. The Consolidated Balance Sheets have $4 million and $12 million of cash and cash equivalents as of December 31, 2015 and 2014, respectively.

Accounts Receivable and Allowance for Doubtful Accounts

Accounts receivable are recorded at the invoiced amount and do not bear interest. It is the policy of management to review the outstanding accounts receivable at least quarterly, as well as the bad debt write-offs experienced in the past. Based on this review, management determined that no allowance for doubtful accounts was required as of December 31, 2015 and 2014.

Inventory

Materials and supplies inventory is valued at cost and is subsequently recorded at the lower of cost or market. During the years ended December 31, 2014 and 2013, the Partnership recorded write-downs to market value related to materials and supplies inventory disposed or identified as excess or obsolete of $9 million and $2 million, respectively. There were no material write-downs related to materials and supplies inventory for the year ended December 31, 2015. Materials and supplies are recorded to inventory when purchased and, as appropriate, subsequently charged to operation and maintenance expense on the Combined and Consolidated Statements of Income or capitalized to property, plant and equipment on the Consolidated Balance Sheets when installed.

Natural gas inventory is held, through the Transportation and Storage segment, to provide operational support for the intrastate pipeline deliveries and to manage leased intrastate storage capacity. Natural gas liquids inventory is held, through the Gathering and Processing segment, due to timing differences between the production of certain natural gas liquids and ultimate sale to third parties. Natural gas and natural gas liquids inventory is valued using moving average cost and is subsequently recorded at the lower of cost or market. During the years ended December 31, 2015, 2014 and 2013, the Partnership recorded write-downs to market value related to natural gas and natural gas liquids inventory of $13 million, $4 million and $4 million, respectively. The cost of gas associated with sales of natural gas and natural gas liquids inventory is presented in Cost of natural gas and natural gas liquids, excluding depreciation and amortization on the Combined and Consolidated Statements of Income.

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

Gas Imbalances

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

Long-Lived Assets (including Intangible Assets)

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

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

The Partnership periodically evaluates long-lived assets, including property, plant and equipment, and specifically identifiable intangibles other than goodwill, when events or changes in circumstances indicate that the carrying value of these assets may not be recoverable. The determination of whether an impairment has occurred is based on an estimate of undiscounted cash flows attributable to the assets, as compared to the carrying value of the assets. For more information, see Note 11.

The Partnership assesses its goodwill for impairment annually on October 1st, or more frequently if events or changes in circumstances indicate that the carrying value of goodwill may not be recoverable. Goodwill is assessed for impairment by comparing the fair value of the reporting unit with its book value, including goodwill. The Partnership tested its goodwill for impairment on May 1, 2013 upon formation and following formation tests annually on October 1. The Partnership utilizes the market or income approaches to estimate the fair value of the reporting unit, also giving consideration to the alternative cost approach. Under the market approach, historical and current year forecasted cash flows are multiplied by a market multiple to determine fair value. Under the income approach, anticipated cash flows over a period of years plus a terminal value are discounted to present value using appropriate discount rates. If the estimated fair value of the reporting unit is less than the carrying amount of the reporting unit, then a second step must be completed in order to determine the amount of the goodwill impairment that should be recorded. In the second step, the implied fair value of the reporting unit's goodwill is determined by allocating the reporting unit's fair value to all of its assets and liabilities other than goodwill (including any unrecognized intangible assets) in a manner similar to a purchase price allocation. The resulting implied fair value of the goodwill that results from the application of this second step is then compared to the carrying amount of the goodwill and an impairment charge is recorded for the difference. The Partnership performs its goodwill impairment testing one level below the Transportation and Storage and Gathering and Processing segment level at the operating segment level. For more information, see Note 8.

Regulatory Assets and Liabilities

The Partnership applies the guidance for accounting for regulated operations to portions of the Transportation and Storage segment. The Partnership’s rate-regulated businesses recognize removal costs as a component of depreciation expense in accordance with regulatory treatment. As of each of December 31, 2015 and 2014, these removal costs of $18 million and $16 million, respectively, are classified as regulatory liabilities in the Consolidated Balance Sheets.

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Capitalization of Interest and Allowance for Funds Used During Construction

Allowance for funds used during construction (AFUDC) represents the approximate net composite interest cost of borrowed funds and a reasonable return on the equity funds used for construction. Although AFUDC increases both utility plant and earnings, it is realized in cash when the assets are included in rates for combined entities that apply guidance for accounting for regulated operations. Capitalized interest represents the approximate net composite interest cost of borrowed funds used for construction. Interest and AFUDC are capitalized as a component of projects under construction and will be amortized over the assets' estimated useful lives. During the years ended December 31, 2015, 2014 and 2013, the Partnership capitalized interest and AFUDC of $10 million, $8 million and $7 million, respectively.

Derivative Instruments

The Partnership is exposed to various market risks. These risks arise from transactions entered into in the normal course of business. At times, the Partnership utilizes derivative instruments such as physical forward contracts, financial futures and swaps to mitigate the impact of changes in commodity prices on its operating results and cash flows. Such derivatives are recognized in the Partnership's Consolidated Balance Sheets at their fair value unless the Partnership elects hedge accounting or the normal purchase and sales exemption for qualified physical transactions. A derivative may be designated as a normal purchase or normal sale if the intent is to physically receive or deliver the product for use or sale in the normal course of business.

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

Fair Value Measurements

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

Equity Based Compensation

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

Reverse Unit Split

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

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

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

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Partnership, including material increases in capital expenditures and certain equity issuances, entering into transactions with related parties and acquiring, pledging or disposing of certain material assets.

(2) New Accounting Pronouncements

Revenue from Contracts with Customers

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

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

Consolidation

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

Presentation of Debt Issuance Costs

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

In August 2015, the FASB issued ASU No. 2015-15, "Interest—Imputation of Interest: Presentation and Subsequent Measurement of Debt Issuance Costs Associated with Line-of-Credit Arrangements—Amendments to SEC Paragraphs Pursuant to Staff Announcement at June 18, 2015 EITF Meeting." This ASU adds SEC paragraphs pursuant to the

SEC Staff Announcement at the June 18, 2015, Emerging Issues Task Force meeting about the presentation and subsequent measurement of debt issuance costs associated with line-of-credit arrangements to this topic. Given the absence of authoritative guidance within ASU 2015-03 for debt issuance costs related to line-of-credit arrangements, the SEC staff would not object to an entity deferring and presenting debt issuance costs as an asset and subsequently amortizing the deferred debt issuance costs ratably over the term of the line-of-credit arrangement, regardless of whether there are any outstanding borrowings on the line-of-credit arrangement. The Partnership has elected to continue to carry debt issuance costs related to line-of-credit arrangements as an asset and amortize the deferred debt issuance costs over the term of the related line-of-credit arrangement. The Partnership will adopt the amendment in the first quarter of 2016 and has determined the adoption of ASU No. 2015-15 will have no impact on our Combined and Consolidated Financial Statements and related disclosures.

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

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

Simplifying the Measurement of Inventory

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

Simplifying the Accounting for Measurement-Period Adjustments

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

Balance Sheet Classification of Deferred Taxes

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

(3) Acquisitions

Monarch

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

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

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

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

Enogex

Under the acquisition method, the fair value of the consideration transferred by the Partnership to OGE Energy and ArcLight for the contribution of Enogex in exchange for interest in the Partnership was allocated to the assets acquired and liabilities assumed on May 1, 2013 based on their estimated fair value. Enogex’s assets, liabilities and equity are recorded at their estimated fair value as of May 1, 2013, and beginning on May 1, 2013, the Partnership consolidated Enogex.

On May 1, 2013, in accordance with the MFA, CenterPoint Energy, OGE Energy, and ArcLight received 227,508,825 common units, 110,982,805 common units, and 51,527,730 common units, respectively, representing limited partner interests in the Partnership. The fair value of consideration transferred to OGE Energy and ArcLight in exchange for the contribution of Enogex consists of the fair value of the limited and, for OGE Energy only, general partner interests. The Partnership utilized the market approach to estimate the fair value of the limited partner interests, general partner interests and Atoka, also giving consideration to alternative methods such as the income and cost approaches as it relates to the underlying assets and liabilities. The primary inputs for the market valuation were the historical and current year forecasted cash flows and market multiple. The primary inputs for the income approach were forecasted cash flows and the discount rate. The primary inputs for the cost approach were costs for similar assets and ages of the assets. All fair value measurements of assets acquired and liabilities assumed were based on a combination of inputs that were not observable in the market and thus represented Level 3 inputs.

The Partnership incurred no acquisition related costs in the Combined and Consolidated Statement of Income based upon the terms in the MFA.

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The following table summarizes the amounts recognized by the Partnership for the estimated fair value of assets acquired and liabilities assumed for the acquisition of the 100% interest in Enogex as of May 1, 2013 and is reconciled to the consideration transferred by the Partnership:

	Amounts Recognized as of May 1, 2013 (In millions)
Assets	
Current Assets	$192
Property, plant and equipment	3,919
Goodwill	439
Other intangible assets	401
Other assets	21
Total assets	$4,972
Liabilities	
Current liabilities	$393
Long-term debt	745
Other liabilities	20
Total liabilities	1,158
Less: Noncontrolling interest at fair value	26
Fair value of consideration transferred	$3,788

The amounts of Enogex's revenue, operating income, net income and net income attributable to the Partnership included in the Partnership's Combined and Consolidated Statement of Income for the period from May 1, 2013 through December 31, 2013, before eliminations, are as follows (in millions):

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

Impact on Depreciation. The property, plant and equipment acquired from Enogex have differing weighted average useful lives from the existing assets of the Partnership. These assets will be depreciated over a weighted average estimated useful life of 32 years.

Unaudited Pro forma Results of Operations. The Partnership's pro forma results of operations in the combined entity had the acquisition of Enogex been completed on January 1, 2012 are as follows:

	Year ended December 31,	
	2013	2012
	(In millions)	
Unaudited pro forma results of operations:		
Pro forma revenues	$3,120	$2,563
Pro forma operating income	487	558
Pro forma net income	1,638	433
Pro forma net income attributable to Enable Midstream Partners, LP	1,635	431

The unaudited pro forma consolidated results of operations include adjustments to:
- Include the historical results of Enogex beginning on January 1, 2012;
- Include incremental depreciation and amortization incurred on the step-up of Enogex's assets;

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- Include adjustments to revenue and cost of sales to reflect Enogex purchase price adjustments for the recurring impact of certain loss contracts and deferred revenues; and
- Include a reduction to interest expense for recognition of a premium on Enogex's fixed rate senior notes.

The unaudited pro forma information is not necessarily indicative of the results of operations that would have occurred had the transactions been made at the beginning of the periods presented or the future results of the consolidated operations.

(4) Earnings Per Limited Partner Unit

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

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

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

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

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

Prior to May 1, 2013, Enable Midstream Partners, LP Parent Net Equity represents the investment of CenterPoint Energy in the Partnership. On April 30, 2013, immediately prior to formation of the limited partnership, while under common control, CenterPoint Energy completed equity transactions with the Partnership, whereby CenterPoint

Energy made a cash contribution to the Partnership and retained certain assets and liabilities previously held by the Partnership, all of which were deemed to be transfers of net assets not constituting a transfer of a business, as follows:

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	Amounts retained prior to May 1, 2013 (In millions)
Contributions from (Distributions to) CenterPoint Energy	
Cash	$40
Pension and postretirement plans	22
Deferred financing cost	6
Investment in 25.05% of SESH (see Note 9)	(197)
Increase in Notes payable-affiliated companies	(143)
Decrease in Notes receivable-affiliated companies	(45)
Income tax obligations, net	28
Net distributions to CenterPoint Energy prior to formation	$(289)

Effective May 1, 2013, Enable Midstream Partners, LP Partners' Capital on the Consolidated Balance Sheet represents the net amount of capital, accumulated net income, contributions and distributions affecting the investments of CenterPoint Energy, OGE Energy, and ArcLight in the Partnership. On August 14, 2013 and November 14, 2013, the Partnership distributed $61 million and $120 million to the unitholders of record as of July 1, 2013 and October 1, 2013, respectively. On February 14, 2014, May 14, 2014 and August 14, 2014, the Partnership distributed $114 million, $155 million and $22 million to the unitholders of record as of January 1, 2014, April 1, 2014, and April 1, 2014, respectively in accordance with the Partnership's First Amended and Restated Agreement of Limited Partnership.

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

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

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

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

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

General Partner Interest and Incentive Distribution Rights

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

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own.

Subordinated Units

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

Subordination Period

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

(6) Property, Plant and Equipment

Property, plant and equipment includes the following:

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

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

(7) Intangible Assets, Net

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

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Intangible assets consist of the following:

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

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

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

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

(8) Goodwill

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

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

	Gathering and Processing	Transportation and Storage	Total
	(in millions)		

Balance as of December 13, 2013	$489	$579	$1,068
Balance as of December 31, 2014	489	579	1,068
Acquisition of Monarch	19	—	19
Goodwill impairment	(508)	(579)	(1,087)
Balance as of December 31, 2015	$—	$—	$—

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(9) Investments in Equity Method Affiliates

The Partnership uses the equity method of accounting for investments in entities in which it has an ownership interest between 20% and 50% and exercises significant influence. Until May 1, 2013, the Partnership held a 50% investment in SESH, a 286-mile interstate natural gas pipeline, which was accounted for as an investment in equity method affiliates. On May 1, 2013, the Partnership distributed a 25.05% interest in SESH to CenterPoint Energy, retaining a 24.95% interest in SESH.

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

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

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

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

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

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Investment in Equity Method Affiliates:

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

Equity in Earnings of Equity Method Affiliates:

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

Distributions from Equity Method Affiliates:

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

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

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Summarized financial information of SESH is presented below:

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

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

(10) Debt

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

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

(1)

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

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

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

Revolving Credit Facility

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

The Revolving Credit Facility permits outstanding borrowings to bear interest at the LIBOR and/or an alternate base rate, at the Partnership's election, plus an applicable margin. The applicable margin is based on the Partnership's applicable credit ratings. As of December 31, 2015, the applicable margin for LIBOR-based borrowings under the Revolving Credit Facility was 1.50% based on the Partnership's credit ratings. In addition, the Revolving Credit Facility requires the Partnership to pay a fee on unused commitments. The commitment fee is based on the Partnership's applicable credit rating from the rating agencies. As of December 31, 2015, the commitment fee under the Revolving Credit Facility was 0.20% per annum based on the Partnership's credit ratings. The commitment fee is recorded as interest expense in the Partnership's Combined and Consolidated Statements of Income.

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

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

Commercial Paper

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

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Term Loan Facilities

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

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

Senior Notes

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

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

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

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

Financing Costs

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

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

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

(11) Fair Value Measurements

Certain assets and liabilities are recorded at fair value in the Consolidated Balance Sheets and are categorized based upon the level of judgment associated with the inputs used to measure their value. Hierarchical levels, as defined below and directly related to the amount of subjectivity associated with the inputs to fair valuations of these assets and liabilities are as follows:

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

Level 2: Inputs, other than quoted prices included in Level 1, are observable for the asset or liability, either directly or indirectly. Level 2 inputs include quoted prices for similar instruments in active markets, and inputs other than quoted prices that are observable for the asset or liability. Fair value assets and liabilities that are generally included in this category are derivatives with fair values based on inputs from actively quoted markets. Instruments classified as Level 2 include over-the-counter NYMEX natural gas swaps, natural gas basis swaps and natural gas purchase and sales transactions in markets such that the pricing is closely related to the NYMEX pricing, and over-the-counter WTI crude swaps for condensate sales.

Level 3: Inputs are unobservable for the asset or liability, and include situations where there is little, if any, market activity for the asset or liability. Unobservable inputs reflect the Partnership's judgments about the assumptions market participants would use in pricing the asset or liability since limited market data exists. The Partnership develops these inputs based on the best information available, including the Partnership's own data.

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

The Partnership determines the appropriate level for each financial asset and liability on a quarterly basis and recognizes transfers between levels at the end of the reporting period. For the period ended December 31, 2015, there were transfers between 2 and Level 3 investments, as shown in the reconciliation below.

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

Estimated Fair Value of Financial Instruments

The fair values of all accounts receivable, notes receivable, accounts payable, commercial paper and other such financial instruments on the Consolidated Balance Sheets are estimated to be approximately equivalent to their carrying amounts and have been excluded from the table below. The following table summarizes the fair value and carrying amount of the Partnership’s financial instruments at December 31, 2015 and 2014:

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

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

The fair value of the Partnership's Long-term notes payable—affiliated companies, Revolving Credit Facility, and 2015 Term Loan Facility, along with the EOIT Senior Notes and Enable Midstream Partners, LP, 2019, 2024 and 2044 Notes, is based on quoted market prices and estimates of current rates available for similar issues with similar maturities and is classified as Level 2 in the fair value hierarchy.

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

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

During the years ended December 31, 2015, 2014 and 2013, the Partnership remeasured the Service Star assets at fair value. At December 31, 2015 and 2014, management reassessed the carrying value of the Service Star business line, a component of the Gathering and Processing segment which provides measurement and communication services to third parties, based upon higher than expected losses of customers during 2015 and 2014 due to decreases of crude oil and natural gas prices. Upon formation as a private partnership on May 1, 2013, management of the Partnership reassessed the long-term strategy related to the Service Star business line. Based on forecasted future undiscounted cash flows management determined that the carrying value of the Service Star assets were not fully recoverable. The Partnership utilized the income approach (generally accepted valuation approach) to estimate the fair value of these assets. The primary inputs are forecast cash flows and the discount rate. The fair value measurement is based on inputs that are not observable in the market and thus represent level 3 inputs. Applying a discounted cash flow model to the property, plant and equipment and reviewing the associated materials and supplies inventory, during the years ended December 31, 2015, 2014 and 2013, the Partnership recognized a $10 million, $7 million and $12 million impairment, respectively. The $10 million consisted of a $9 million write-down of property, plan and equipment and a $1 million write-down of materials and supplies inventory considered either excess or obsolete. The $7 million impairment consisted of write-downs of property plant, and equipment. The $12 million impairment consisted of a $10 million write-down of property, plant and equipment and a $2 million write-down of materials and supplies inventory considered either excess or obsolete.

At December 31, 2015, due to decreases of crude oil and natural gas prices during 2015, management reassessed the carrying value of the Partnership's investment in the Atoka assets, a component of the Gathering and Processing segment. Based on forecasted future undiscounted cash flows, management determined that the carrying value of the Atoka assets were not fully recoverable. The Partnership utilized the income approach (generally accepted valuation approach) to estimate the fair value of these assets. The primary inputs are forecast cash flows and the discount rate.

The fair value measurement is based on inputs that are not observable in the market and thus represent level 3 inputs. Applying a discounted cash flow model to the property, plant and equipment and intangible assets, the Partnership recognized a $25 million impairment during the year ended December 31, 2015. The $25 million impairment consisted of a $19 million write-down of property plant, and equipment and a $6 million write-down of intangible assets.

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

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Contracts with Master Netting Arrangements

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

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

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

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

(1) The Partnership uses the market approach to fair value its gas imbalance assets and liabilities at individual, or where appropriate an average of, current market indices applicable to the Partnership's operations, not to exceed net realizable value. Gas imbalances held by EOIT are valued using an average of the Inside FERC Gas Market Report for Panhandle Eastern Pipe Line Co. (Texas, Oklahoma Mainline), ONEOK (Oklahoma) and ANR Pipeline (Oklahoma) indices. There were no netting adjustments as of December 31, 2015 and 2014.

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

(3)

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

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Changes in Level 3 Fair Value Measurements

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

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

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

Quantitative Information on Level 3 Fair Value Measurements

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

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

(12) Derivative Instruments and Hedging Activities

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

Commodity Price Risk

The Partnership has used forward physical contracts, commodity price swap contracts and commodity price option features to manage the Partnership's commodity price risk exposures in the past. Commodity derivative instruments used by the Partnership are as follows:

- NGL put options, NGL futures and swaps, and WTI crude futures and swaps for condensate sales are used to manage the Partnership's NGL and condensate exposure associated with its processing agreements;
- natural gas futures and swaps are used to manage the Partnership's keep-whole natural gas exposure associated with its processing operations and the Partnership's natural gas exposure associated with operating its gathering, transportation

and storage assets; and

- natural gas futures and swaps, natural gas options and natural gas commodity purchases and sales are used to manage the Partnership’s natural gas exposure associated with its storage and transportation contracts and asset management activities.

Normal purchases and normal sales contracts are not recorded in Other Assets or Liabilities in the Consolidated Balance Sheets and earnings are recognized and recorded in the period in which physical delivery of the commodity occurs. Management applies normal purchases and normal sales treatment to: (i) commodity contracts for the purchase and sale of natural gas used in

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or produced by the Partnership’s operations and (ii) commodity contracts for the purchase and sale of NGLs produced by the Partnership’s gathering and processing business.

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

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

Credit Risk

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

Derivatives Not Designated As Hedging Instruments

Derivative instruments not designated as hedging instruments for accounting purposes are utilized in the Partnership’s asset management activities. For derivative instruments not designated as hedging instruments, the gain or loss on the derivative is recognized currently in earnings.

Quantitative Disclosures Related to Derivative Instruments

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

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

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

(1) As of December 31, 2015, 97.7% of the natural gas contracts have durations of one year or less and 2.3% have durations of more than one year and less than two years. As of December 31, 2014, 91.2% of the natural gas

contracts had durations of one year or less, 6.5% had durations of more than one year and less than two years and 2.2% have durations of more than two years.

(2) As each of December 31, 2015 and 2014, 100% of the crude oil (for condensate) contracts have durations of one year or less.

(3) As of December 31, 2015, 100% of the natural gas liquid contracts have durations of one year or less.

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Balance Sheet Presentation Related to Derivative Instruments

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

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

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

Income Statement Presentation Related to Derivative Instruments

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

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

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

Credit-Risk Related Contingent Features in Derivative Instruments

In the event Moody's Investors Services or Standard & Poor's Ratings Services were to lower the Partnership's senior unsecured debt rating to a below investment grade rating, at December 31, 2015, the Partnership would have been required to post no cash collateral to satisfy its obligation under its financial and physical contracts relating to derivative instruments that are in a net liability position at December 31, 2015. In addition, the Partnership could be required to provide additional credit assurances in future dealings with third parties, which could include letters of credit or cash collateral.

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(13) Supplemental Disclosure of Cash Flow Information

The following table provides information regarding supplemental cash flow information:

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

(14) Related Party Transactions

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

Revenues

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

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

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

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Cost of natural gas purchases

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

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

Corporate services and seconded employee expense

Prior to May 1, 2013, the Partnership had employees and reflected the associated benefit costs directly and not as corporate services. Under the terms of the MFA, effective May 1, 2013 the Partnership's employees were seconded by CenterPoint Energy and OGE Energy, and the Partnership began reimbursing each of CenterPoint Energy and OGE Energy for all employee costs under the seconding agreements until the seconded employees transition from CenterPoint Energy and OGE Energy to the Partnership. The Partnership transitioned seconded employees from CenterPoint Energy and OGE Energy to the Partnership effective January 1, 2015, except for certain employees who are participants under OGE Energy's defined benefit and retiree medical plans, who will remain seconded to the Partnership, subject to certain termination rights of the Partnership and OGE Energy. The Partnership's reimbursement of OGE Energy for seconded employee costs arising out of OGE Energy's defined benefit and retiree medical plans is fixed at $6 million in each of 2015 and 2016, $5 million in 2017, and at actual cost subject to a cap of $5 million in 2018 and thereafter, in the event of continued secondment.

Prior to May 1, 2013, the Partnership received certain services and support functions from CenterPoint Energy described below. Under the terms of the MFA, effective May 1, 2013, the Partnership receives services and support functions from each of CenterPoint Energy and OGE Energy under service agreements for an initial term ending on April 30, 2016. The service agreements automatically extend year-to-year at the end of the initial term, unless terminated by the Partnership with at least 90 days' notice. Additionally, the Partnership may terminate these service agreements at any time with 180 days' notice, if approved by the Board of Enable GP. The Partnership reimburses CenterPoint Energy and OGE Energy for these services up to annual caps, which for 2015 are $15 million and $11 million, respectively.

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

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

(1)

Beginning on May 1, 2013, CenterPoint Energy assumed all employees of the Partnership and seconded such employees to the Partnership. Therefore, costs historically incurred directly by the Partnership for employment services are reflected as seconded employee costs subsequent to formation on May 1, 2013.

(2) Corporate services and seconded employee expenses from OGE Energy are reflected in the Combined and Consolidated Statements of Income beginning on May 1, 2013.

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Notes payable

The Partnership has outstanding long-term notes payable—affiliated companies to CenterPoint Energy at both December 31, 2015 and 2014 of $363 million which mature in 2017. Notes having an aggregate principal amount of approximately $273 million bear a fixed interest rate of 2.10% and notes having an aggregate principal amount of approximately $90 million bear a fixed interest rate of 2.45%.

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

Notes receivable

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

Other

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

(15) Commitments and Contingencies

Long-Term Agreements

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

Operating Lease Obligations. The Partnership has operating lease obligations expiring at various dates. Future minimum payments for noncancellable operating leases are as follows:

	Year Ended December 31,						
	2016	2017	2018	2019	2020	After 2020	Total
	(In millions)						
Noncancellable operating leases	$14	$5	$3	$1	$—	$—	$23

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

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

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

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and maintenance expense in the Statements of Combined and Consolidated Income.

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

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

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

Legal, Regulatory and Other Matters

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

(16) Income Taxes

Prior to May 1, 2013, the Partnership was included in the consolidated income tax returns of CenterPoint Energy. The Partnership calculated its income tax provision on a separate return basis under a tax sharing agreement with CenterPoint Energy.

Upon conversion to a limited partnership on May 1, 2013, the Partnership's earnings are generally no longer subject to income tax (other than Texas state margin taxes and taxes associated with the Partnership's corporate subsidiary, Enable Midstream Services) and are taxable at the individual partner level. The Partnership and its subsidiaries are pass-through entities for federal income tax purposes. For these entities, all income, expenses, gains, losses and tax credits generated flow through to their owners and, accordingly, do not result in a provision for income taxes in the combined and consolidated financial statements. Consequently, the Combined and Consolidated Statements of Income do not include an income tax provision for income earned on or after May 1, 2013 (other than Texas state margin taxes and taxes associated with the Partnership's corporate subsidiary, Enable Midstream Services).

The items comprising income tax expense are as follows:

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

State	(1)	1	(155)
Total provision (benefit) for deferred income taxes, net	(1)	1	(1,194)
Total income tax expense (benefit)	$—	$2	$(1,192)

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The following schedule reconciles the statutory Federal income tax rate to the effective income tax rate:

	Year Ended December 31,		
	2015	2014	2013
	(In millions)		
Income before income taxes	$(771)	$535	$426
Federal statutory rate	— %	— %	35 %
Expected federal income tax expense	—	—	149
Increase in tax expense resulting from:			
State income taxes, net of federal income tax	—	2	8
Income not subject to tax	—	—	(103)
Conversion to partnership	—	—	(1,240)
Other, net	—	—	(6)
Total	—	2	(1,341)
Total income tax expense (benefit)	$—	$2	$(1,192)
Effective tax rate	— %	0.4 %	(275.9)%

As a result of the conversion to a limited partnership, CenterPoint Energy assumed all outstanding current income tax liabilities and the deferred income tax assets and liabilities were eliminated by recording a provision for income tax benefit equal to $1.24 billion. Therefore there were no federal deferred income tax assets or liability balances at December 31, 2015 and 2014 related to the Partnership.

Enable Midstream Services is subject to U.S. federal and state income taxes. Deferred income tax assets and liabilities for the operations of this corporation are recognized for temporary differences between the assets and liabilities for financial reporting and tax purposes. Changes in tax legislation are included in the relevant computations in the period in which such changes are effective.

The components of Deferred Income Taxes as of December 31, 2015 and 2014 were as follows:

	December 31,	
	2015	2014
	(In millions)	
Deferred tax assets:	$—	$—
Deferred tax liabilities:		
Non-current:		
Depreciation	9	9
Other	(1)	—
Total non-current deferred tax liabilities	8	9
Accumulated deferred income taxes, net	$8	$9

Uncertain Income Tax Positions

The Partnership recognizes interest and penalties as a component of income tax expense. There were no unrecognized tax benefits as of December 31, 2015, 2014 and 2013.

Tax Audits and Settlements

CenterPoint Energy’s consolidated federal income tax returns have been audited by the IRS and settled through the 2013 tax year. The federal income tax return of the Partnership has been audited through the 2013 tax year.

(17) Equity Based Compensation

Enable GP has adopted the Enable Midstream Partners, LP Long Term Incentive Plan for officers, directors and employees of the Partnership, Enable GP or affiliates, including any individual who provides services to the Partnership or Enable GP as a seconded employee, and any consultants or affiliates of Enable GP or other individuals who perform services for the Partnership.

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The long term incentive plan consists of the following components: phantom units, performance units, appreciations rights, restricted units, option rights, cash incentive awards, distribution equivalent rights or other unit-based awards and unit awards. The purpose of awards under the long term incentive plan is to provide additional incentive compensation to employees providing services to the Partnership, and to align the economic interests of such employees with the interests of unitholders. The long term incentive plan will limit the number of units that may be delivered pursuant to vested awards to 13,100,000 common units, subject to proportionate adjustment in the event of unit splits and similar events. Common units cancelled, forfeited, expired or cash settled will be available for delivery pursuant to other awards. The plan is administered by the Board of Directors or a designated committee thereof.

The following table summarizes the Partnership's compensation expense for the years ended December 31, 2015, 2014, and 2013 related to performance units, restricted units, and phantom units for the Partnership's employees and independent directors:

	Year Ended December 31,		
	2015	2014	2013
	(In millions)		
Performance units	$3	$3	$—
Restricted units	7	10	—
Phantom units	1	2	—
Total compensation expense	$11	$15	$—

Performance Units

The Board of Directors has authorized various grants of performance based phantom units (performance units) under the Long Term Incentive Plan pursuant to the 2014 Long Term Incentive Plan Annual Award Program, to certain employees providing services to the Partnership, including executive officers, that cliff vest three years from the grant date. The performance units provide for accelerated vesting if there is a change in control (as defined in the Enable Midstream Partners, LP Long Term Incentive Plan). Each performance unit is subject to forfeiture if the recipient terminates employment with the Partnership prior to the end of the three-year award cycle for any reason other than death, disability or retirement. In the event of death or disability, a participant will receive a payment based on the targeted achievement of the performance goals during the award cycle. In the event of retirement, a participant will receive a pro rated payment based on the target performance, rather than actual performance, of the performance goals during the award cycle.

The payment of performance units is dependent upon the Partnership's total unitholder return ranking relative to a peer group of companies over the period of January 1, 2015 through December 31, 2017 as compared to a target set at the time of the grant by the Board of Directors. Any performance units that cliff vest three years from the grant date (i.e. the three year award cycle) will be payable in the Partnership's common units. All of these performance units are classified as equity in the Partnership's Consolidated Balance Sheet. If there is no or only a partial payout for the performance units at the end of the award cycle, the unearned performance units are canceled. Payout requires approval of the Board of Directors.

The fair value of the performance units was estimated on the grant date using a lattice-based valuation model that factors in information, including the expected distribution yield, expected price volatility, risk-free interest rate and the probable outcome of the market condition, over the expected life of the performance units. Compensation expense for the performance units is a fixed amount determined at the grant date fair value and is recognized over the three-year award cycle regardless of whether performance units are awarded at the end of the award cycle. Distributions are accumulated and paid at vesting, and therefore, are not included in the fair value calculation.

Due to the short trading history of the Partnership's common units, expected price volatility is based on one year of daily stock price observations, combined with the average of the two-year volatility of the peer group companies used to determine the total unitholder return ranking. The risk-free interest rate for the performance unit grants is based on the three-year U.S. Treasury yield curve in effect at the time of the grant. The expected life of the units is based on the non-vested period since inception of the award cycle. There are no post-vesting restrictions related to the Partnership's performance units. The number of performance units granted based on total unitholder return and the assumptions used to calculate the grant date fair value of the performance units based on total unitholder return are shown in the following table.

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	2015	2014
Number of units granted	501,474	563,963
Fair value of units granted	$16.59	$26.12
Expected price volatility	27.6 %	22.2 %
Risk-free interest rate	0.99 %	0.83 %
Expected life of units (in years)	3.00	3.00

Restricted Units

The Board of Directors has authorized various grants of time-based restricted units (restricted units) to certain employees providing services to the Partnership that are subject to cliff vesting over various terms, not longer than four years from the grant date. Prior to vesting, each share of restricted stock is subject to forfeiture if the recipient ceases to render substantial services to the Partnership for any reason other than death, disability or retirement. During the restriction period these units may not be sold, assigned, transferred or pledged and are subject to a risk of forfeiture.

On April 16, 2014, 375,000 restricted units were granted to the Chief Executive Officer of Enable GP, of which 40% vested on August 1, 2014, 20% vested on February 1, 2015 and 40% vested on July 15, 2015. Additionally, on April 16, 2014, the Board of Directors granted 150,000 restricted units to the Chief Executive Officer of Enable GP, which 50% vested on May 29, 2015 and 50% was forfeited upon his departure. On April 16, 2014, 137,500 restricted units were granted to the Chief Financial Officer of Enable GP, which vested 45.46% on March 1, 2015 and will vest 54.54% on March 1, 2016. Additionally, on April 16, 2014, 25,000 restricted units were granted to the Chief Financial Officer of Enable GP, which vest four years from the grant date. Prior to vesting, each share of restricted stock is subject to forfeiture if the recipient ceases to render substantial services to the Partnership for any reason other than death, disability or retirement. During the restriction period these units may not be sold, assigned, transferred or pledged and are subject to a risk of forfeiture.

The fair value of the restricted units was based on the closing market price of the Partnership’s common unit on the grant date. Compensation expense for the restricted units is a fixed amount determined at the grant date fair value and is recognized as services are rendered by employees over a vesting period, as defined in the agreements. Distributions are paid as declared prior to vesting and, therefore, are included in the fair value calculation. After payment, distributions are not subject to forfeiture. The expected life of the restricted units is based on the non-vested period since inception of the award cycle. There are no post-vesting restrictions related to the Partnership's restricted units.

The number of restricted units granted related to the Partnership’s employees and the grant date fair value are shown in the following table.

	2015	2014
Restricted units granted on April 16, 2014 to the Chief Executive Officer and Chief Financial Officer of Enable GP	—	687,500
Fair value of restricted units granted	$—	$22.60
Restricted units granted to the Partnership's employees	279,677	304,901
Fair value of restricted units granted	$16.75 - $19.18	$23.56 - $25.50

Phantom Units

On April 21, 2014, 100,000 time-based phantom units (phantom units) were granted to certain employees providing services to the Partnership, including executive officers, that vested on the first anniversary of the date of grant. Prior to vesting, each share of restricted units was subject to forfeiture if the recipient ceased to render substantial services to the Partnership for any reason other than death, disability or retirement. During the restriction period these units may not be sold, assigned, transferred or pledged and were subject to a risk of forfeiture.

During 2014, the Board of Directors granted 6,718 phantom units to the independent directors of Enable GP, for their service as directors, which vested one year from the grant date.

The fair value of the phantom units was based on the closing market price of the Partnership’s common unit on the grant date. Compensation expense for the phantom unit is a fixed amount determined at the grant date fair value and is recognized as services are rendered by employees over a one-year vesting period. Distributions are accumulated and paid at vesting and, therefore,

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are not included in the fair value calculation. The expected life of the phantom unit is based on the non-vested period since inception of the one-year award cycle. There are no post-vesting restrictions related to the Partnership's phantom unit. The number of phantom units granted and the grant date fair value are shown in the following table.

	2015	2014
Phantom units granted	9,817	106,718
Fair value of phantom units granted	$12.70	$23.16 - $23.70

Other Awards

During 2015, the Board of Directors granted 17,384 common units to the independent directors of Enable GP, for their service as directors, which vested immediately. The fair value of the common units was based on the closing market price of the Partnership's common unit on the grant date.

	2015
Common units granted	17,384
Fair value of common units granted	$11.12

Units Outstanding

A summary of the activity for the Partnership's performance units, restricted units, and phantom units as of December 31, 2015 and changes in 2015 are shown in the following table.

	Performance Units		Restricted Stock		Phantom Units		Other Awards	
	Number of Units	Weighted Average Grant-Date Fair Value, Per Unit	Number of Units	Weighted Average Grant-Date Fair Value, Per Unit	Number of Units	Weighted Average Grant-Date Fair Value, Per Unit	Number of Units	Weighted Average Grant-Date Fair Value, Per Unit
	(In millions, except unit data)							
Units Outstanding at 12/31/2014	552,581	$ 26.12	838,068	$ 23.47	98,718	$ 23.20	—	$ —
Granted[(1)]	501,474	16.59	279,677	17.14	9,817	12.70	17,384	11.12
Vested	(1,254)	26.12	(400,801)	22.72	(96,718)	23.20	(17,384)	11.12
Forfeited	(238,291)	24.70	(135,172)	23.06	(2,000)	23.16	—	—
Units Outstanding at 12/31/2015	814,510	20.67	581,772	21.04	9,817	12.70	—	—
Aggregate Intrinsic Value of Units Outstanding at 12/31/2015	$6		$5		$—		$—	

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

A summary of the Partnership's performance, restricted, and phantom units' aggregate intrinsic value (market value at vesting date) and fair value of units vested (market value at date of grant) during the year ended December 31, 2015 are shown in the following table.

	December 31, 2015		
	Performance Units	Restricted Stock	Phantom Units
	(In millions)		
Aggregate Intrinsic Value of Units Vested	$—	$10	$2
Fair Value of Units Vested	—	13	2

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Unrecognized Compensation Cost

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

	December 31, 2015	
	Unrecognized Compensation Cost (In millions)	Weighted Average to be Recognized (In years)
Performance Units	$11	2.07
Restricted Units	8	1.74
Phantom Units	—	0.35
Total	$19	

As of December 31, 2015, there were 11,054,681 units available for issuance under the long term incentive plan.

(18) Reportable Segments

The Partnership’s determination of reportable segments considers the strategic operating units under which it manages sales, allocates resources and assesses performance of various products and services to wholesale or retail customers in differing regulatory environments. The accounting policies of the reportable segments are the same as those described in the summary of significant accounting policies described in Note 1, which explain that some executive benefit costs of the Partnership prior to May 1, 2013 have not been allocated to reportable segments. The Partnership uses operating income as the measure of profit or loss for its reportable segments.

The Partnership’s assets and operations are organized into two reportable segments: (i) Gathering and Processing, which primarily provides natural gas gathering, processing and fractionation services and crude oil gathering for our producer customers, and (ii) Transportation and Storage, which provides interstate and intrastate natural gas pipeline transportation and storage service primarily to natural gas producers, utilities and industrial customers. Effective May 1, 2013, the intrastate natural gas pipeline operations acquired from Enogex were combined with the interstate pipelines in the transportation and storage segment and the non-rate regulated natural gas gathering, processing and treating operations acquired from Enogex were combined within the gathering and processing segment.

Financial data for reportable segments are as follows:

Year Ended December 31, 2015	Gathering and Processing	Transportation and Storage (1)	Eliminations	Total
	(In millions)			
Revenues (2)	$1,663	$1,132	$(377)	$2,418
Cost of natural gas and natural gas liquids	908	565	(376)	1,097
Operation and maintenance, General and administrative	293	230	(1)	522
Depreciation and amortization	195	123	—	318
Impairments	543	591	—	1,134
Taxes other than income tax	30	29	—	59
Operating (loss) income	$(306)	$(406)	$—	$(712)
Total assets	$7,548	$4,976	$(1,286)	$11,238

Capital expenditures	$839	$110	$—	$949

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Year Ended December 31, 2014	Gathering and Processing	Transportation and Storage (1)	Eliminations	Total
	(In millions)			
Revenues (2)	$2,424	$1,577	$(634)	$3,367
Cost of natural gas and natural gas liquids	1,585	961	(632)	1,914
Operation and maintenance, General and administrative	297	232	(2)	527
Depreciation and amortization	160	116	—	276
Impairments	8	—	—	8
Taxes other than income tax	25	31	—	56
Operating income	$349	$237	$—	$586
Total assets	$8,356	$5,493	$(2,012)	$11,837
Capital expenditures	$740	$103	$(6)	$837

Year Ended December 31, 2013	Gathering and Processing	Transportation and Storage (1)	Eliminations	Total
	(In millions)			
Revenues (2)	$1,740	$1,149	$(400)	$2,489
Cost of natural gas and natural gas liquids	1,075	636	(398)	1,313
Operation and maintenance, General and administrative	222	209	(2)	429
Depreciation and amortization	117	95	—	212
Impairments	12	—	—	12
Taxes other than income tax	20	34	—	54
Operating income	$294	$175	$—	$469
Total assets	$7,157	$5,717	$(1,642)	$11,232
Capital expenditures	$431	$142	$—	$573

(1) See Note 9 for discussion regarding ownership interest in SESH and related equity earnings included in the Transportation and Storage segment for the years ended December 31, 2015, 2014 and 2013.

(2) The Partnership had no external customers accounting for 10% or more of revenues in periods shown. See Note 14 for revenues from affiliated companies.

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(19) Quarterly Financial Data (Unaudited)

Summarized unaudited quarterly financial data for 2015 and 2014 are as follows:

	Quarters Ended			
	March 31, 2015	June 30, 2015	September 30, 2015	December 31, 2015
	(in millions, except per unit data)			
Revenues	$616	$590	$646	$566
Cost of natural gas and natural gas liquids	292	277	287	241
Operating income (loss) (1)	104	93	(975)	66
Net income (loss)	91	77	(991)	52
Net income (loss) attributable to Enable Midstream Partners, LP	91	77	(985)	65
Basic and diluted earnings (loss) per common limited partner unit	$0.22	$0.18	$(2.33)	$0.15
Basic and diluted earnings (loss) per subordinated limited partner unit	$0.21	$0.18	$(2.34)	$0.15

	Quarters Ended			
	March 31, 2014	June 30, 2014	September 30, 2014	December 31, 2014
	(in millions, except per unit data)			
Revenues	$1,002	$827	$803	$735
Cost of natural gas and natural gas liquids	633	478	439	364
Operating income	162	138	152	134
Net income	150	121	139	123
Net income attributable to Enable Midstream Partners, LP	149	120	139	122
Basic and diluted earnings per common limited partner unit	$0.38	$0.29	$0.33	$0.29
Basic and diluted earnings per subordinated limited partner unit	$—	$0.29	$0.33	$0.29

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(1) In the third quarter of 2015, the Partnership recorded a $1,087 million impairment to goodwill. For more information see Note 8.

(20) Subsequent Events

Preferred Units

On January 28, 2016, the Partnership entered into a Purchase Agreement (the Purchase Agreement) with CenterPoint Energy to issue and sell in a Private Placement an aggregate of 14,520,000 10% Series A Fixed-to-Floating Non-Cumulative Redeemable Perpetual Preferred Units (Preferred Units) for a cash purchase price of $25.00 per Preferred Unit, resulting in total gross proceeds of $363 million. The closing of the Private Placement, which is expected to occur prior to the end of the first quarter of 2016, is subject to the completion of due diligence by the

CenterPoint Energy, including the review of the Partnership’s audited financial statements and this Form 10-K, and certain customary closing conditions. In connection with the Private Placement, the Partnership intends to redeem the $363 million of Notes payable—affiliated companies scheduled to mature in 2017 payable to a subsidiary of CenterPoint Energy.

Pursuant to the Purchase Agreement, in connection with the closing of the Private Placement, the General Partner will execute a Third Amended and Restated Agreement of Limited Partnership of the Partnership (the Amended Partnership Agreement) to, among other things, authorize and establish the terms of the Preferred Units and the other series of preferred units that are issuable upon conversion of the Preferred Units, in the form attached as an exhibit to the Purchase Agreement. Also, the Partnership has agreed to enter into a Registration Rights Agreement with CenterPoint Energy at the closing of the Private Placement, pursuant to which, among other things, the Partnership will give CenterPoint Energy certain rights to require the Partnership to file and maintain a registration statement with respect to the resale of the Preferred Units and any other series of preferred units or common units representing limited partnership interests in the Partnership that are issuable upon conversion of the Preferred Units.

Debt

On February 2, 2016, Standard & Poor's Ratings Services lowered its credit rating on the Partnership from an investment grade rating to a noninvestment grade rating. The short-term rating on the Partnership was also reduced from an investment grade rating to a noninvestment grade rating. As a result, we expect our access to our commercial paper program to be limited until these ratings improve. As of February 15, 2016, the Partnership repaid $214 million of commercial paper outstanding at December 31, 2015, and subsequently borrowed $355 million under the Revolving Credit Facility.

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) under the Securities Exchange Act of 1934, as amended (the "Exchange Act")) as of December 31, 2015. Based on such evaluation, our management has concluded that, as of December 31, 2015, 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). 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.

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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, 2015, 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, 2015.

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. See Item 8. "Financial Statements and Supplementary Data."

Changes in Internal Controls

There were no changes in our internal controls over financial reporting during the quarter ended December 31, 2015, that have materially affected, or that are reasonably likely to materially affect, our internal control over financial reporting.

Item 9B. Other Information

See discussion of the Second Amendment to the Enable Midstream Partners, LP Short Term Incentive Plan effective February 16, 2016 under Item 11. “Executive Compensation —2016 Executive Compensation—Short-Term Incentives.”

See discussion of the Enable Midstream Partners, LP Long Term Incentive Plan Annual Performance Unit Award Agreement for Senior Officers and the Enable Midstream Partners, LP Long Term Incentive Plan Annual Phantom Unit Award Agreement for Senior Officers under Item 11. “Executive Compensation —2016 Executive Compensation—Long-Term Incentives.”

On February 16, 2016, C. Scott Hobbs informed the Board of Directors of his intent to resign as a director effective February 29, 2016. Mr. Hobbs is a member of the Audit Committee and the Conflicts Committee of the Board of Directors. Mr. Hobbs' decision to resigned was not the result of any disagreement with the Partnership or its general partner. In connection with Mr. Hobbs' resignation, Mr. Hobbs will receive a one-time payment of $13,000 in recognition of his service in 2016. The Board of Directors is in the process of searching for Mr. Hobbs' replacement.

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 and one alternative director. 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:

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- 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 shows information regarding the current directors and executive officers of Enable GP. The business address of each of the directors and officers is listed below.

Name	Age	Title
Peter B. Delaney(1)	62	Director
Alan N. Harris(1)	62	Director
C. Scott Hobbs(1)	62	Director
Peter H. Kind(1)	59	Director
Stephen E. Merrill(2)	51	Alternate Director
Scott M. Prochazka(3)	49	Director and Chairman
William D. Rogers(3)	55	Director
Sean Trauschke(2)	48	Director
Paul M. Brewer(1)	57	Executive Vice President—Operations
Deanna J. Farmer(1)	50	Executive Vice President and Chief Administrative Officer
John P. Laws(1)	41	Executive Vice President, Chief Financial Officer and Treasurer
Rodney J. Sailor(1)	57	Director, President and Chief Executive Officer
Mark C. Schroeder(3)	59	Executive Vice President and General Counsel

(1) One Leadership Square, 211 North Robinson Avenue, Suite 150, Oklahoma City, Oklahoma 73102
(2) 321 North Harvey, P.O. Box 321, Oklahoma City, Oklahoma 73101
(3) 1111 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.

Peter B. Delaney has been a Director of our general partner since May 2013 and served as interim President and Chief Executive Officer of our general partner from May 29, 2015 to December 31, 2015. Mr. Delaney is a member of the Board of Directors of OGE Energy. Previously, Mr. Delaney served as Chairman of OGE Energy and OG&E until November 30, 2015; as Chairman and Chief Executive Officer of OGE Energy and OG&E from July 2013 to May 29, 2015; as Chairman, President and Chief Executive Officer of OGE Energy and OG&E from December 2011 to July 2013; as Chairman and Chief Executive Officer of OGE Energy and OG&E from January 2011 to December 2011; as Chairman, President and Chief Executive Officer of OGE Energy and OG&E from September 2007 to December 2010; and served as the Chief Executive Officer of Enogex Holdings and Chief Executive Officer of Enogex from 2010 to 2013. Mr. Delaney is a member of the Board of Directors of the Federal Reserve Bank of Kansas City. Mr. Delaney has been a director of OGE Energy and OG&E since January 2007. We believe Mr. Delaney's extensive knowledge of the industry and us, our operations and people, gained with OGE Energy and its affiliates in positions of increasing responsibility provides the Board with valuable experience.

Alan N. Harris has been a Director of our general partner since February 2015. Mr. Harris retired from Spectra Energy Corp in January 2015. Mr. Harris joined Spectra Energy Corp. in 1982 and served in multiple roles with increasing responsibilities.

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Most recently, he served as Senior Advisor to the Chairman, President and Chief Executive Officer of Spectra Energy Corp. In his role, Mr. Harris provided oversight and focus for Spectra Energy Corp's project execution efforts. From 2009 through 2013, Mr. Harris served as Chief Development and Operations Officer of Spectra Energy Corp. In that dual role, Mr. Harris oversaw the company's strategy, business development, and mergers and acquisitions, as well as project execution, the operations of Spectra Energy Corp's U.S. pipeline and storage business, environment, health and safety, and the company's master limited partnership. Mr. Harris served as Chief Development Officer of Spectra Energy Corp from 2007 to 2009 and has served as a member of the Board of Directors of the general partner of DCP Midstream Partners, LP from January 2014 through October 2014 and from January 2009 through April 2012. We believe that Mr. Harris' extensive knowledge of the industry provides the Board with valuable experience.

C. Scott Hobbs has been a Director of our general partner since June 2014. Since 2006, Mr. Hobbs has provided consulting and advisory services to clients evaluating major projects, acquisitions, and divestitures principally involving assets in the energy industry. Prior to 2006, Mr. Hobbs served in various senior leadership roles in the energy industry, including executive chairman of Optigas, Inc., a private midstream gas company, as President and Chief Operating Officer of KFX, Inc., a public company developing clean coal technologies and Chief Operating Officer of Colorado Interstate Gas Co., a subsidiary of Coastal. Mr. Hobbs is currently a director of SunCoke Energy Partners GP, LLC, the general partner of SunCoke Energy Partners, L.P., where he is Chairman of the conflicts committee and a member of the audit committee, Mr. Hobbs has previously served as a Director of Buckeye GP LLC, the general partner of Buckeye Partners, L.P., American Oil and Gas Inc. and CVR Energy Inc. from October 2007 to May 2014. We believe Mr. Hobbs’ experience in leadership roles in the energy industry provides the Board with valuable experience in overseeing the management of our operations. On February 16, 2016, C. Scott Hobbs informed the Board of Directors of his intent to resign as a director effective February 29, 2016.

Peter H. Kind has been a Director of our general partner since February 2014. Mr. Kind is Executive Director of Energy Infrastructure Advocates LLC, an independent financial and strategic advisory firm. Previously, Mr. Kind was a Senior Managing Director of Macquarie Capital, an investment banking firm from 2009 to 2011 and a Managing Director of Bank of America Securities from 2005 to 2009. Mr. Kind is a director of Southwest Water Company, a privately held company, where he is a member of the audit committee, and a director of the general partner of NextEra Energy Partners, LP, where he is an audit committee member and chairman of the conflicts committee. We believe Mr. Kind, with more than 30 years of experience providing corporate and investment banking services to the utility and energy industries, provides the Board with valuable experience in financial and capital markets matters. Mr. Kind, a Certified Public Accountant, also has experience in the audit of large public energy companies.

Stephen E. Merrill has been an alternate Director of our general partner since May 2015. Mr. Merrill is Chief Financial Officer of OGE Energy and OG&E. Previously, Mr. Merrill served as Executive Vice President and Chief Administrative Officer of our general partner from April 2014 to August 2014; as Executive Vice President of Finance and Chief Administrative Officer of our general partner from December 2013 to April 2014; Chief Operating Officer of Enogex from 2011 through April 2014; Vice President-Human Resources of OGE Energy from 2009 to 2011; and Vice President and Chief Financial Officer of Enogex from 2008 to 2011. We believe Mr. Merrill’s energy industry provides the Board with valuable experience in overseeing the management of our operation and financial experience provides the Board with valuable experience in our financial and accounting matters.

Scott M. Prochazka has been a Director of our general partner since November 2013 and has served as Chairman of the Board of our general partner since May 29, 2015. Mr. Prochazka is President and Chief Executive Officer of CenterPoint Energy. Previously, Mr. Prochazka served as Executive Vice President and Chief Operating Officer from August 2012 to November 2013; Senior Vice President and Division President, Electric Operations of CenterPoint Energy from May 2011 to July 2012; and as Division Senior Vice President, Electric Operations of CenterPoint Energy’s wholly owned subsidiary, CenterPoint Energy Houston Electric, LLC, from February 2009 to May 2011. Mr. Prochazka has served as a director of CenterPoint Energy since November 2013. We believe Mr. Prochazka’s extensive knowledge of the industry and us, our operations and people, gained in his years of service with CenterPoint Energy in positions of increasing responsibility provides the Board with valuable experience.

William D. Rogers has been a Director of our general partner since August 2015 and previously served as an alternate Director of our general partner from May 2015 through July 2015. Mr. Rogers is Executive Vice President and Chief Financial Officer of CenterPoint Energy. Previously, Mr. Rogers served as Executive Vice President, Finance and Accounting of CenterPoint Energy from February 2015 through March 2015; Vice President and Treasurer of American Water Works Company, Inc. from October 2010 to January 2015; and Chief Financial Officer of NV Energy, Inc. from February 2007 through February 2010. We believe Mr. Roger's financial experience provides the Board with valuable experience in our financial and accounting matters.

Sean Trauschke has been a Director of our general partner since May 2013. From May 2013 to December 2013, he served as Acting Chief Financial Officer of our general partner. Mr. Trauschke is Chairman, President and Chief Executive Officer of OGE Energy and OG&E. Previously, Mr. Trauschke served as President and Chief Executive Officer of OGE Energy and OG&E from May 29, 2015 to November 30, 2015; as President of OGE Energy and OG&E from September 2014 to May 29, 2015; as

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Vice President and Chief Financial Officer of OGE Energy from 2009 to September 2014; Vice President and Chief Financial Officer of OG&E from 2009 to July 2013; Chief Financial Officer of Enogex Holdings from 2010 to 2013; Chief Financial Officer of Enogex LLC from 2009 to 2013; and Senior Vice President-Investor Relations and Financial Planning of Duke Energy from 2008 to 2009. We believe Mr. Trauschke's energy industry and financial experience provides the Board with valuable experience in our financial and accounting matters.

Paul M. Brewer has served as Executive Vice President—Field Operations of our general partner since January 2016. Previously, Mr. Brewer served as Senior Vice President—Field Operations and Environmental, Health & Safety of our general partner from February 2014 to January 2016; Senior Vice President Field Operations and Engineering & Construction of our general partner from December 2013 to February 2014; Senior Vice President Environmental, Health & Safety and Compliance Services of our general partner from October 2013 to December 2013; Senior Vice President—Project Management Office from July 2013 to October 2013; Vice President of Operations of our general partner from May 2013 to July 2013; and Vice President of Operations of Enogex from June 2008 to May 2013. Earlier in his career, Mr. Brewer spent 12 years with DCP Midstream and its predecessor companies and over 13 years with Mobil Oil and its predecessor companies.

Deanna J. Farmer has served as Executive Vice President and Chief Administrative Officer of our general partner since September 2014. Previously, Ms. Farmer served as Vice President of Corporate Services and Chief Information Officer of the general partner of Access Midstream Partners, LP from June 2014 to September 2014; Vice President of Corporate Services and Human Resources of the general partner of Access Midstream Partners, LP from September 2013 to June 2014; Director of Finance and Information Management of the general partner of Chesapeake Midstream Partners, LP from February 2010 to September 2012; and Director of Information Technology of Chesapeake Energy, Inc. from 2007 to February 2010.

John P. Laws has served as Executive Vice President and Chief Financial Officer of our general partner since January 2016 and as Treasurer of our general partner since December 2013. Previously, Mr. Laws served as Vice President of our general partner from April 2014 to January 2016; as Vice President of Planning and Development of Enable Oklahoma Intrastate Transmission, LLC from May 2013 to December 2013; as Vice President of Planning and Development of Enogex Holdings, LLC from November 2011 to May 2013; and as Managing Director of Finance of Enogex, LLC from January 2010 through November 2011.

Rodney J. Sailor has served as a Director and as President and Chief Executive Officer of our general partner since January 1, 2016. Previously, Mr. Sailor served as Chief Financial Officer of our general partner from March 2014 to December 2015 and Executive Vice President of our general partner from April 2014 to December 2015; Senior Vice President and Chief Financial Officer of WPX Energy, Inc. from December 2011 to March 2014; and as Vice President and Treasurer of the Williams Companies, Inc. from 2005 to 2011. Prior to 2005, Mr. Sailor served in various capacities, including finance, accounting and business development roles for The Williams Companies, Inc. Mr. Sailor served as a Director of Williams Partners GP LLC, the general partner of Williams Partners L.P., from October 2007 to 2010; served as a director of Apco Oil and Gas International Inc. from September 2006 to March 2014; and as Chief Financial Officer of Apco from December 2012 to March 2014. We believe Mr. Sailor's energy industry and financial experience provides the Board with valuable experience in overseeing the management of our operations.

Mark C. Schroeder has served as the General Counsel of our general partner since July 2013 and as Executive Vice President of our general partner since April 2014. Previously, Mr. Schroeder served as Senior Vice President and Deputy General Counsel of CenterPoint Energy from July 2011 to February 2014; and Vice President and General Counsel-Midstream of CenterPoint Energy from August 2003 to July 2011.

Board of Directors

Chairmanship

Scott M. Prochazka has served as chairman of the Board of Directors since May 29, 2015. Mr. Prochazka's term will expire on May 1, 2017, at which time OGE Energy will have the right to appoint the next chairman. Under the limited liability company agreement of our general partner, the right to appoint the chairman of the Board of Directors will rotate between CenterPoint Energy and OGE Energy every two years. 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

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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 Williams D. Rogers were appointed by CenterPoint Energy. Directors Peter B. Delaney and Sean Trauschke, as well as alternate director Stephen E. Merrill, were appointed by OGE Energy. Alternate directors are entitled to receive notice of and attend meetings of the Board of Directors as an observer, unless they are serving in place of a director designated by the party who appointed them. Alternate directors, in the sole discretion of the party appointing them, can serve in place of a Director designated by the party who appointed them at any meeting of the Board of Directors or in connection with any action or approval by the Board of 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, C. Scott Hobbs, 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 C. Scott Hobbs 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 C. Scott Hobbs 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 ultimate responsibility and authority to the board’s Compensation Committee for the compensation of our named executive officers who are employed by us.

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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.

Compliance with Section 16(a) of the Exchange Act

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, except as follows: (i) Alan N. Harris, director, inadvertently (a) reported acquisition of 4,196 common units rather than 6,594 common units, which was subsequently corrected by filing a Form 4/A and (b) failed to timely report four acquisitions totaling 186 common units; (ii) Paul M. Brewer, Executive Vice President—Operations, inadvertently (a) omitted a grant of 6,000 restricted units from his Form 3 and (b) failed to timely report the withholding for taxes of 1,957 common units; and (iii) Rodney J. Sailor, Director, President and Chief Executive Officer, inadvertently failed to timely report the withholding for taxes of 21,801 common units.

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, 2015 are Peter B. Delaney, who served as interim President and Chief Executive Officer from May 29, 2015 until his departure on December 31, 2015, Deanna J. Farmer, Executive Vice President and Chief Administrative Officer, Rodney J. Sailor, who served as Executive Vice President and Chief Financial Officer until December 31, 2015 and who now serves as our President and Chief Executive Officer, Mark C. Schroeder, Executive Vice President and General Counsel, Paul Weissgarber, who served as Chief Commercial Officer until his resignation on February 11, 2016, and Lynn L. Bourdon III, who served as President and Chief Executive Officer until his resignation on May 29, 2015.

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Except for Mr. Delaney, our named executive officers were employed and compensated by us during 2015. Mr. Delaney was employed and compensated by OGE Energy from May 29, 2015 to December 1, 2015. During this time, we reimbursed OGE Energy $100,000 per month for Mr. Delaney's services, and Mr. Delaney did not receive any compensation or benefits from us. Mr. Delaney was employed and compensated by us during December 2015. During this time, we paid Mr. Delaney a salary of $100,000 as his sole compensation, and Mr. Delaney waived all rights to receive any other compensation or benefits from us.

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 executives with those of our unitholders. Our overall compensation philosophy is pay for performance. We seek to motivate our executives to achieve individual and business performance objectives by designing their compensation packages to align with our values, strategy, and financial results. We believe that executives 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, the Compensation Committee makes recommendations to the Board of Directors, but any such grants require the approval of the full Board of Directors.

Role of Consultant. To provide advice on the form and amount of executive compensation in 2015, our Compensation Committee engaged Mercer LLC ("Mercer"), an independent compensation consulting firm. Mercer's services included a compensation risk assessment and an analysis of 2015 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 2015 executive compensation, Mercer provided market data for a peer group consisting of the following companies:

Atlas Pipeline Partners, LP
Boardwalk Pipeline Partners, LP
DCP Midstream Partners, LP
MarkWest Energy, Partners LP
ONEOK Partners, LP
Regency Energy Partners LP

Enbridge Energy Partners, LP	Spectra Energy Partners, LP
EnLink Midstream Partners, LP	Targa Resources Partners LP
Magellan Midstream Partners, LP	Western Gas Partners, LP

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 2015, 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 named executive officers, our Chief Executive Officer and our Chief Administrative Officer have roles in determining executive compensation policies and programs. Our Chief Executive Officer and our Chief

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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 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 Board of Directors, with respect to the long-term incentive plan, and the Compensation Committee, with respect to the short-term incentive plan, for its consideration and approval.

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, which is based on a percentage of annual base salary; and (3) the present value of an equity based grant under our long-term incentive plan, which is 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. Base salary is the foundation of total compensation. Base salary recognizes the job being performed and the value of that job in the competitive market. Base salaries are designed 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 executives from the performance of their responsibilities. Annual adjustments to base salary primarily reflect either changes or responses to changes in market data or increased experience and individual contribution of the employee. Base salaries are set and adjustments to base salaries are made using market data from the Compensation Committee’s consultant, and we target a range of 80% to 120% of the market median for each position.

Short-Term Incentives. We adopted the Enable Midstream Partners, LP Short-Term Incentive Plan for 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 selects 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. We adopted the Enable Midstream Partners, LP Long-Term Incentive Plan for 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 Compensation Committee selects the employees who will be participants for each plan year, determines each named executive officer’s long-term incentive target, the terms and conditions of awards for participants, including any goals, determines whether goals are achieved, and whether any awards are paid. The Compensation Committee recommends to the Board of Directors, and the Board of Directors determines, each named executive officer’s long-term incentive target. Determinations regarding who will be participants, the terms and conditions of awards, and each named executive officer’s long-term incentive target are made using market data from the Compensation Committee's consultant.

The long-term incentive plan is administered by the Compensation Committee. 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 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.

Upon completion of the Offering, Mr. Sailor received an award of 25,000 restricted units, which will vest on April 16, 2018. The vesting of these awards is contingent upon the executive’s employment with us on the vesting date. Notwithstanding the foregoing: (i) in the event we terminate the executive’s employment, other than for cause, after the first anniversary of his employment date, a portion of this award will vest upon his termination date based upon the number of days during the four-year vesting period that he is employed by us, but in no event less than 50% of the award amount; (ii) in the event the executive’s employment is terminated due to death or disability, by the Partnership within 2 years following a change in control for any reason other than cause, or by the executive for good reason, the award will vest; and (iii) in the event the executive’s employment is terminated to due to retirement, a portion of this award will vest upon his retirement based on the number of days during the four-year vesting period that he is employed by us.

In order to compensate them for forfeiting compensation from their previous employers, Mr. Sailor received an award of 137,500 restricted units upon completion of the Offering, Ms. Farmer received an award of 24,000 restricted units upon her employment with us, and Mr. Weissgarber received an award of 45,230 restricted units upon his employment with us. 62,508 units of Mr. Sailor’s award vested on March 1, 2015, and 74,992 units of Mr. Sailor’s award will vest on March 1, 2016. 12,000 of Ms. Farmer’s units vested on September 1, 2015 and 12,000 will vest on September 1, 2016. Mr. Weissgarber's 45,230 units were forfeited upon his departure. The vesting of each award is contingent upon the executive’s employment with us on the vesting date. Notwithstanding the foregoing, each award will vest in the event: (i) we terminate the executive’s employment other than for cause within two years following a change in control; (ii) the executive’s employment is terminated due to death or disability; or (iii) the executive terminates his employment for good reason within two years following a change in control.

For the restricted unit awards to Mr. Sailor upon the completion of the Offering: (i) “good reason” means our failure to maintain him in at least the position he occupied upon his employment with our general partner or its successor entity, a significant adverse change in his authorities, powers, functions, responsibilities or duties, our failure to perform our obligations with respect to his compensation arrangement, or the relocation of his principal office by more than 50 miles within two years following a change in control; and (ii) termination “for cause” means gross negligence in the performance of duties, conviction of a felony, or intentional misconduct that results in substantial injury to the Partnership. For the other restricted 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 his or her 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.

Upon completion of the Offering, Mr. Bourdon received an award of 150,000 restricted units, of which 75,000 vested on May 29, 2015, and 75,000 were forfeited upon his departure. In addition, in order to compensate him for forfeiting compensation from his previous employers, Mr. Bourdon received an award of 375,000 restricted units upon completion of the Offering, of which, 150,000 units vested on August 1, 2014, 75,000 units vested on February 1, 2015, and 150,000 units vested on July 15, 2015.

Please read "—Potential Payments Upon Termination or Change-in-Control" below for further information on the severance arrangements with Mr. Bourdon and Mr. Weissgarber.

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Other Compensation and Benefits. Our named executive officers, other than Mr. Delaney, 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; however, during 2015, Mr. Delaney was not eligible to participate in any of our employee benefit plans and programs.

2015 Executive Compensation

In 2015, 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	
Peter B. Delaney	$100,000	—	%	—	%
Deanna J. Farmer	$325,000 (increase of 3.2%)	70	%	125	%
Rodney J. Sailor	$450,000	100	%	200	%
Mark C. Schroeder	$325,000 (increase of 8.3%)	70	%	125	%
Paul Weissgarber	$345,000	70	%	150	%
Lynn L. Bourdon III	$600,000	100	%	300	%

Short-Term Incentives. For 2015, the target amount of the short-term incentive award for each named executive officer, other than Mr. Delaney, was a percentage of actual base salary paid during 2015, with a payout ranging from 0% to 150% of the target 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 2015 award, the performance goals were based 20% on safety targets, 30% on operation and maintenance (O&M)and general and administrative (G&A) expense targets, and 50% on a distributable cash flow per unit (DCFU) target. 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%, based on the actual performance achieved. The following table shows the minimum, target, and maximum levels of performance for the performance goals set for 2015, 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
DCFU	$1.278/unit	$1.325/unit	$1.413/unit	$1.256/unit	—
O&M and G&A	$536 million	$525 million	$515 million	$505 million	150%
Safety Targets					
TRIR	0.777	0.607	0.389	0.443	138%
PVIR	0.983	0.885	0.492	1.199	—

The calculation of the DCFU target was derived from the amounts reported in our 2015 financial statements, as adjusted for: (1) increases or decreases resulting from changes in accounting principles that become effective after

December 31, 2014; (2) the effect of any acquisition of any additional interest in SESH; and (3) adjustments to reflect the effect of any acquisitions or divestitures occurring during the 2015 plan year as permitted under the plan. The calculation of the O&M and G&A target was derived from the amounts of O&M and G&A reported in our 2015 financial statements, as adjusted for: (1) increases or decreases in O&M attributable to a change in accounting principles effective after December 31, 2014; (2) any increases or decreases in O&M attributable to gains, losses, or impairments; (3) any increases or decreases in O&M attributable to additional severance or relocation associated with a restructuring event implemented after March 2015; and (4) adjustments to reflect the effect of any acquisitions or divestitures occurring during the 2015 plan year as permitted under the plan. The safety performance goals consisted of the (i) total recordable incident rate (TRIR), which is derived from the Federal Occupational Safety and Health Act of 1970 standards for recordable injuries and illnesses (excluding hearing shifts and any recordable injury resulting from a non-preventable

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vehicle incident), and (ii) preventable vehicle incident rate (PVIR), which is defined as one in which the driver failed to exercise every reasonable precaution to prevent the accident. The payout that each named executive officer actually received was subject to increase (not to exceed 200% of target) or decrease at the discretion of the Compensation Committee based on the named executive officer’s personal performance.

Long-Term Incentives. For 2015, each named executive officer, other than Mr. Delaney and Mr. Bourdon, received a long-term incentive award of performance units with distribution equivalent rights under the long-term incentive plan that will vest on June 1, 2018, subject to the satisfaction of vesting criteria. The target amount of the performance unit award for each participating named executive officer is a percentage of base salary, with 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, 2015 through December 31, 2017. Performance units earned will be paid in the Partnership's common units, and distribution equivalent rights will be paid in cash.

For the 2015 award, 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 may be adjusted by the Compensation Committee, as necessary, from time to time:

Boardwalk Pipeline Partners, LP	Magellan Midstream Partners, LP
Buckeye Partners, LP	MarkWest Energy Partners, LP
Crestwood Midstream Partners LP	Martin Midstream Partners LP
DCP Midstream Partners, LP	ONEOK Partners, L.P.
Enbridge Energy Partners, LP	Plains All American Pipeline, LP
Energy Transfer Partners, L.P.	Spectra Energy Partners, LP
EnLink Midstream, LP	Targa Resources Partners LP
Enterprise Products Partners L.P.	Western Gas Partners, LP
Genesis Energy, LP	Williams Partners L.P.

If our TUR ranking among the peer group over the performance period is below the 30^{th} percentile, no performance units will vest. If our TUR ranking is greater than or equal to the 30^{th} percentile but less than the 50^{th} percentile, 50%-100% of the performance units will vest. If our TUR ranking is greater than or equal to the 50^{th} percentile but less than the 75^{th} percentile, 101%-150% of the performance units will vest. If our TUR ranking is greater than or equal to the 75^{th} percentile but less than the 90^{th} percentile, 151%-199% of the performance units will vest. If our TUR ranking is greater than or equal to the 90^{th} percentile, 200% of the performance units will vest. If our ranking falls between these percentages, vesting will be determined by straight-line interpolation.

The vesting of this award 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, by the Partnership following a change in control for any reason other than cause, or by the executive following a change in control for good reason, the award will vest; and (ii) in the event the executive’s employment is terminated due to retirement, a portion of this award will vest upon their retirement based on the number of days during the three-year vesting period that they are employed by us.

For the performance 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.

2016 Executive Compensation

Following Mr. Bourdon's resignation on May 29, 2015 and Mr. Delaney's departure on December 31, 2015, Mr. Sailor became President and Chief Executive Officer on January 1, 2016, and Mr. Laws became Executive Vice President, Chief Financial Officer and Treasurer on January 14, 2016. Effective with their respective appointments, Mr. Sailor's annual base salary was increased to $600,000 and long-term incentive target was increased to 300% of base salary, and Mr. Laws' annual base salary was increased to $315,000. Mr. Weissgarber resigned from his position as Chief Commercial Officer on February 11, 2016.

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In February 2016, the Compensation Committee reviewed the base salary and short-term incentive target for Ms. Farmer, Mr. Laws, Mr. Sailor and Mr. Schroeder, and the Board of Directors reviewed the long-term incentive target for Ms. Farmer, Mr. Laws, Mr. Sailor and Mr. Schroeder, in each case in comparison to market data provided by the Compensation Committee's consultant. In connection with this review, Mr. Laws' short-term incentive target was increased to 70% of base salary, and long-term incentive target was increased to 175% of base salary. No changes were made to the base salaries, short-term incentive targets, or long-term incentive targets for Ms. Farmer, Mr. Sailor or Mr. Schroeder, and no changes were made to the base salary of Mr. Laws.

For 2016, the base salary, short-term incentive target and long-term incentive target for the following executive officers are (excluding Mr. Bourdon, who resigned on May 29, 2015, Mr. Delaney, who departed on December 31, 2015 and Mr. Weissgarber, who resigned on February 11, 2016):

Name	Base Salary	Short-Term Incentive Target	Long-Term Incentive Target
Deanna J. Farmer	$325,000	70 %	125 %
John P. Laws	$315,000	70 %	175 %
Rodney J. Sailor	$600,000	100 %	300 %
Mark C. Schroeder	$325,000	70 %	125 %

Short-Term Incentives. The Compensation Committee has not yet determined the 2016 short-term incentive performance goals for our named executive officers. We expect the Compensation Committee to make this determination prior to March 31, 2016.

In February 2016, the Compensation Committee adopted an amendment to our short-term incentive plan to incorporate any claw back policy that may be adopted by the Compensation Committee from time to time. We anticipate that the Compensation Committee will adopt a claw back policy in 2016 that will require our named executive officers to return certain incentive-based compensation, including certain awards under our short-term incentive plan, if their conduct resulted in a restatement of our earnings.

Long-Term Incentives. In February 2016, the Board determined that our named executive officers’ 2016 long-term incentive awards will be allocated 80% to performance units and 20% to phantom units. The Board determined that 2016 performance unit awards will be consistent with 2015, including having distribution equivalent rights and being based on total unitholder return over a three-year performance cycle. For 2016, total unitholder return will be based on the relative performance of our common units compared to the following peer group, which may be adjusted by the Compensation Committee, as necessary, from time to time:

Antero Midstream Partners LP	EQT Midstream Partners LP
Archrock Partners, L.P.	MPLX LP (acquiring MarkWest Energy Partners, LP)
Boardwalk Pipeline Partners, LP	ONEOK Partners, L.P.
Columbia Pipeline Partners LP	Spectra Energy Partners, LP
Crestwood Midstream Partners LP	Summit Midstream Partners, LP
DCP Midstream Partners, LP	Targa Resources Partners LP
Dominion Midstream Partners LP	TC Pipelines, LP
Energy Transfer Partners, L.P.	Western Gas Partners, LP
EnLink Midstream, LP	Williams Partners, L.P.
Enterprise Products Partners L.P.	

The Board also determined that phantom unit awards will have distribution equivalent rights and will vest three years from the date of grant. The vesting of these awards will be 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, by the Partnership following a change in control for any reason other than cause, or by the executive following a change in control for good reason, the award will vest; and (ii) in the event the executive’s employment is terminated due to retirement, a portion of this award will vest upon his or her retirement based on the number of days during the three-year vesting period that he or she is employed by us. “Good reason” and “for cause” have will have the same meanings for phantom unit awards as they do for performance unit awards.

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For both performance unit awards and phantom unit awards, the Board determined that the date of grant will be April 1, 2016. Provided that they are employed by us on the date of grant, the following executive officers will receive the following 2016 performance unit and phantom unit awards:

Name	Performance Awards	Phantom Awards
Deanna J. Farmer	46,830	11,708
John P. Laws	63,545	15,886
Rodney J. Sailor	207,493	51,873
Mark C. Schroeder	46,830	11,708

For both performance unit awards and phantom unit awards, the Board of Directors determined that the awards should be subject to the any claw back policy that may be adopted by the Compensation Committee. As a result, we have modified our form of performance unit and phantom unit award agreements for our named executive officers to incorporate any claw back policy that may be adopted by the Compensation Committee from time-to-time.

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, the other named executive officers should own common units of the Partnership having a market value of three times their respective base salaries, and that our independent directors should own common units of the Partnership equal to 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, units owned indirectly (such as by a spouse or a trust), restricted units and phantom units granted under our long term incentive plan, and performance units granted under our long term incentive plan (at target) count towards 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.

Executive Compensation Tables

The following table summarizes the compensation for our named executive officers for the years ended December 31, 2015 and 2014. For all our named executive officers, the table includes all compensation awarded by or paid by us during the year ended December 31, 2015 and 2014. For Mr. Schroeder, the table also includes all compensation expenses reimbursed to CenterPoint Energy from his secondment to us on March 1, 2014 through December 31, 2014.

We are not providing, and the table does not include, compensation for Mr. Schroeder prior to his secondment to us on March 1, 2014. From our formation on May 1, 2013 through February 28, 2014, Mr. Schroeder provided services to us pursuant to a services agreement with CenterPoint Energy. Amounts allocated to us for services provided to us by

Mr. Schroeder during this period were based on an allocation of overhead and other costs of the services provided. On March 1, 2014, Mr. Schroeder was seconded to us under our transitional seconding agreement with CenterPoint Energy.

We are not providing, and the table does not include, compensation for Mr. Delaney prior to being employed by us on December 1, 2015. From his appointment as interim President and Chief Executive Officer on May 29, 2015 through December 1, 2015, Mr. Delaney was employed by OGE Energy, and we reimbursed OGE Energy $100,000 per month for Mr. Delaney's services. From December 1, 2015 through December 31, 2015, Mr. Delaney was employed by us, received a salary of $100,000, and waive all rights to receive any other compensation or benefits from us.

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Summary Compensation Table

Name and Principal Position	Year	Salary ($)	Bonus ($)	Stock Awards ($)(1)	Option Awards ($)	Non-Equity Incentive Plan Compensation ($)(2)	Change in Pension Value and Nonqualified Deferred Compensation Earnings ($)(3)	All Other Compensation ($)(4)	Total ($)
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
Peter B. Delaney interim President and Chief Executive Officer	2015	100,000 (5)	—	—	—	—	—	—	100,000
Deanna J. Farmer	2015	311,846	—	398,575 (14)	—	117,054	—	67,511	894,986
Executive Vice President and Chief Administrative Officer	2014	81,173 (6)	182,000 (12)	591,600	—	—	—	15,787	870,560
Rodney J. Sailor	2015	436,154	—	882,970 (15)	—	278,720		192,111	1,789,955
Executive Vice President and Chief Financial Officer	2014	339,231 (7)	125,000 (13)	4,710,503	—	379,600	—	115,196	5,669,530
Mark C. Schroeder	2015	307,115	—	398,575	—	115,278	—	57,695	878,663
Executive Vice President and General Counsel	2014	250,001 (8)	—	461,810	—	155,000	30,908	50,854	948,573
Paul Weissgarber Chief Commercial Officer	2015	331,731 (9)	175,000 (13)	1,375,232 (16)	—	—	—	114,891	1,996,854
Lynn L. Bourdon, III	2015	246,923 (10)	—	—	—	—	—	1,423,401	1,670,324
former President and Chief	2014	550,000 (11)	2,000,000 (13)	13,940,980 (17)	—	479,000	—	231,854	17,201,834

Executive
Officer

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(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 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 2015 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 2015 and included in this column would be $797,150 for Ms. Farmer, $1,765,939 for Mr. Sailor, $797,150 for Mr. Schroeder and $1,882,952 for Mr. Weissgarber. Assuming achievement of the performance goals at the maximum level, the grant date fair value of the performance units granted in 2014 and included in this column would be $2,076,006 for Mr. Sailor and $692,019 for Mr. Schroeder. Awards granted to Ms. Farmer in 2014 are restricted unit awards and calculated based on the closing price of the Partnership's common units, as reported on the NYSE on the grant date.

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

(3) Amounts in this column reflect the actuarial increase in the present value of Mr. Schroeder's benefits under CenterPoint Energy's qualified defined benefit pension plans as reported to us by CenterPoint Energy, which CenterPoint Energy has represented to us was reported in the Notes to CenterPoint Energy’s Consolidated Financial Statements for the year ended December 31, 2014 that was included in CenterPoint Energy’s 10-K for the year ended December 31, 2014. Under the terms of the Master Formation Agreement, the Partnership has no current or future liability for any accumulated pension obligations under CenterPoint Energy's qualified defined benefit pension plans. During 2014, the Partnership reimbursed CenterPoint Energy for the aggregate period costs recognized by CenterPoint Energy in accordance with FASB ASC Topic 718 attributable to participants seconded to us by CenterPoint Energy. Such period costs were not allocated to individual participants.

(4) The following table sets forth the elements of All Other Compensation for 2014 and 2015.

Name (18)		401(k) Plan Matching Contributions ($)	Non-Qualified Matching Contributions ($)	Distribution Equivalent Rights ($)	Severance ($)(19)	Vacation Payout ($)	Supplemental Life Insurance ($)	Long Term Disability ($)	Total ($)
Peter B. Delaney	2015	—	—	—	—	—	—	—	—
Deanna J. Farmer	2015	29,150	10,653	26,310	—	—	630	768	67,511
	2014	8,527	—	7,260	—	—	—	—	15,787
Rodney J. Sailor	2015	29,150	60,583	99,804	—	—	1,806	768	192,111
	2014	26,000	—	89,196	—	—	—	—	115,196
Mark C. Schroeder	2015	29,150	21,683	4,288	—	—	1,806	768	57,695
	2014	13,000	9,731	22,642	—	4,615	107	759	50,854
Paul Weissgarber	2015	29,150	26,590	56,775	—	—	1,667	709	114,891
Lynn L. Bourdon, III	2015	29,150	50,702	186,375	1,156,440	—	409	325	1,423,401
	2014	26,000	—	205,854	—	—	—	—	231,854

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(5) Represents salary from December 1, 2015 to December 31, 2015. Mr. Delaney was employed and compensated by OGE Energy from May 29, 2015 to December 1, 2015. During this time, we reimbursed OGE Energy $100,000 per month for Mr. Delaney's services.

(6) Represents salary from hire date on September 29, 2014 to December 31, 2014.

(7) Represents salary from hire date on April 1, 2014 to December 31, 2014.

(8) Represents salary during secondment to the Partnership from March 1, 2014 to December 31, 2014.

(9) Represents salary from hire date on January 5, 2015 to December 31, 2015.

(10) Represents salary from January 1, 2015 to May 29, 2015, which is the effective date of Mr. Bourdon's departure.

(11) Represents salary from hire date on February 1, 2014 to December 31, 2014.

(12) Amount represents a $132,000 signing bonus upon employment with the Partnership and a $50,000 discretionary bonus. Although Ms. Farmer was not eligible to receive an award for 2014 under the Partnership’s Short-Term Incentive Plan, the Compensation Committee elected to pay Ms. Farmer a discretionary bonus of $50,000 that was calculated in accordance with the methodology used for 2014 awards to named executive officers under the Short-Term Incentive Plan.

(13) Amount represents a signing bonus upon employment with the Partnership.

(14) Amounts include an award of 24,000 restricted units Ms. Farmer received upon employment with the Partnership, of which 12,000 units vested on September 1, 2015 (3,913 of these units were withheld for taxes) and 12,000 units will vest on September 1, 2016.

(15) Amounts include an award of 25,000 restricted units Mr. Sailor received upon completion of the Offering which will vest on April 16, 2018; 137,500 restricted units Mr. Sailor received upon completion of the Offering, of which 62,508 units vested on March 1, 2015 (21,801 of these units were withheld for taxes) and 74,992 units will vest on March 1, 2016.

(16) Amounts include an award of 45,230 restricted units Mr. Weissgarber received upon employment with the Partnership, which was forfeited upon his resignation.

(17) Amounts include an award of 150,000 restricted units Mr. Bourdon received upon completion of the Offering, which, but for his resignation, would have vested on April 16, 2018; 375,000 restricted units Mr. Bourdon received upon completion of the Offering, of which150,000 units vested on August 1, 2014 (62,925 of these units were withheld for taxes), 75,000 units vested on February 1, 2015, and, but for his resignation, 75,000 units would have vested on February 1, 2016 and 2017.

(18) None of our named executive officers received perquisites valued in excess of $10,000 in 2015.

(19) In connection with Mr. Bourdon’s May 29, 2015 departure, Mr. Bourdon and the Partnership negotiated a severance agreement that was consistent with the severance terms agreed upon at the time of his hiring, which terms provided for a lump-sum cash payment equal to his annual salary of $600,000; his annual target bonus of

$600,000; plus an allowance of $7,241 representing 6 months of the Partnership portion of COBRA insurance coverage. This lump-sum payment was offset by $50,801 for an erroneous payment made prior to his departure. In addition, the remaining 150,000 restricted common units granted to Mr. Bourdon at the time of his hire that had not yet vested were accelerated at a value of $2,127,000, and one-half of the 150,000 restricted common units granted to Mr. Bourdon in connection with the Partnership's initial public offering in April 2014 were vested at a value of $1,335,000. The lump-sum cash payment is reflected in All Other Compensation, but the accelerated vesting is included in the 2015 Option Exercises and Stock Vested Table.

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Grants of Plan-Based Awards Table

The following Grants of Plan-Based Awards Table summarizes the grants of plan-based awards made to named executive officers during 2015.

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 (#)	Grant Date Fair Value of Stock Awards ($)(3)
			Threshold ($)	Target ($)	Maximum ($)	Threshold (#)	Target (#)	Maximum (#)		
(a)	(b)		(c)	(d)	(e)	(f)	(g)	(h)	(i)	(l)
Peter B. Delaney	—	—	—	—	—	—	—	—	—	—
Deanna J. Farmer	02/09/2015	02/09/2015	109,146	218,292	436,584	—	—	—	—	—
	06/01/2015	05/01/2015	—	—	—	12,013	24,025	48,050	—	398,575
Rodney J. Sailor	02/09/2015	02/09/2015	218,077	436,154	872,308	—	—	—	—	—
	06/01/2015	05/01/2015	—	—	—	26,612	53,223	106,446	—	882,970
Mark C. Schroeder	02/09/2015	02/09/2015	107,491	214,981	429,962	—	—	—	—	—
	06/01/2015	05/01/2015	—	—	—	12,013	24,025	48,050	—	398,575
Paul Weissgarber	02/09/2015	02/09/2015	116,106	232,212	464,424	—	—	—	—	—
	06/01/2015	05/01/2015	—	—	—	15,302	30,604	61,208	—	507,720
	01/05/2015 (4)	12/18/2014	—	—	—	—	—	—	45,230	867,511
Lynn L. Bourdon, III	—	—	—	—	—	—	—	—	—	—

(1) Amounts in columns (c), (d) and (e) of the Grants of Plan-Based Awards Table for 2015 above represent the threshold, target and maximum amounts that would be payable to named executive officers pursuant to the 2015 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 a distributable cash flow per unit target (50%), operations & maintenance expense (30%) and a safety target (20%).

(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. Due to their variable nature, accumulated distribution equivalent rights are not disclosed in the table above. The conditions of the 2015 award entitle the named executive officer to receive from 0 percent to 200 percent of the performance units granted depending upon the Partnership’s total unitholder return over a three-year period (defined as unit price increase (decrease) since December 31, 2014 plus distributions paid, divided by unit price at December 31, 2014) measured against the total unitholder return for such period of our performance peer group consisting of 18 companies. At the end of the three-year period (i.e., December 31, 2017), the terms of these performance units provide for payout of 100 percent 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 percent 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 percent 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 reflect the grant date fair value based on a probable value of these awards or target value, of 100% payout. See Note 17 to the financial statements for further information.

(4) This award was received upon Mr. Weissgarber's employment with the Partnership, which was effective on January 5, 2015. This award was forfeited upon Mr. Weissgarber’s resignation on February 11, 2016.

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Outstanding Equity Awards at 2015 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)
Peter B. Delaney	—		—	—		—
Deanna J. Farmer	12,000	(1)	110,400	12,013	(4)	110,515
Rodney J. Sailor	99,992	(2)	919,926	26,612	(4)	244,826
	—		—	20,353	(5)	187,248
Mark C. Schroeder	—		—	12,013	(4)	110,515
	—		—	6,785	(5)	62,417
	—		—	4,350	(6) (7)	79,866
Paul Weissgarber	45,230	(3)	416,116	15,302	(4)	140,778
Lynn L. Bourdon, III	—		—	—		—

(1) This amount represents a restricted unit award under the Enable Midstream Partners long-term incentive plan scheduled to vest on September 1, 2016. Values were calculated based on a $9.20 closing price of the Partnership's common units, as reported on the NYSE at December 31, 2015.

(2) This amount represents two restricted unit awards under the Enable Midstream Partners long-term incentive plan, of which 74,992 will vest on March 1, 2016 and 25,000 will vest on April 16, 2018. Values were calculated based on a $9.20 closing price of the Partnership's common units, as reported on the NYSE at December 31, 2015.

(3) This amount represents a restricted unit award under the Enable Midstream Partners long-term incentive plan forfeited upon Mr. Weissgarber's resignation on February 11, 2016. Values were calculated based on a $9.20 closing price of the Partnership's common units, as reported on the NYSE at December 31, 2015.

(4) This amount represents a performance unit award under the Enable Midstream Partners long-term incentive plan. The performance cycle began on January 1, 2015 and ends December 31, 2017. The number of units listed reflects the number of units paid at threshold performance. The value of the awards were calculated based on threshold performance of 50% and a $9.20 closing price of the Partnership's common units, as reported on the NYSE on December 31, 2015. The performance unit award for Mr. Weissgarber was forfeited upon his resignation on February 11, 2016.

(5) This amount represents a performance unit award under the Enable Midstream Partners long-term incentive plan. The performance cycle began on April 11, 2014 and ends December 31, 2016. The number of units listed reflects the number of units paid at threshold performance. The value of the awards were calculated based on threshold payout of 50% and a $9.20 closing price of the Partnership's common units, as reported on the NYSE on December 31, 2015.

(6) This amount represents awards under the CenterPoint Energy long-term incentive plan. This amount represents the portion of the performance units allocated to us for the performance period of January 1, 2013 through December 31, 2015. 2,000 shares are subject to only one achievement level, the remaining 4,700 are shown at threshold

achievement of 50%. Each performance share will be payable, if earned in one share of CenterPoint Energy common stock. Values were calculated based on a $18.36 closing price of CenterPoint Energy's common stock, as reported on the NYSE at December 31, 2015.

(7) The amount of performance units reported in the 2014 10-K was 9,050, which was in error.

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2015 Option Exercises and Stock Vested Table

Name	Stock Awards Number of Shares Acquired on Vesting (#)		Value Realized on Vesting ($) (7)
(a)	(d)		(e)
Peter B. Delaney	—		—
Deanna J. Farmer	12,000	(1)	181,920
Rodney J. Sailor	62,508	(2)	1,125,144
Mark C. Schroeder	5,000	(3)	84,900
	3,765	(5)	79,140
	2,200	(6)	47,806
Paul Weissgarber	—		—
Lynn L. Bourdon, III	300,000	(4)	4,795,500

(1) This amount reflects the distribution of 12,000 restricted units granted on September 29, 2014. The units vested on September 1, 2015 and the award was paid out in units of the Partnership.

(2) This amount reflects the distribution of 62,508 restricted units granted on April 16, 2014. The units vested on March 1, 2015 and the award was paid out in units of the Partnership.

(3) This amount reflects the distribution of 5,000 phantom units granted on April 21, 2014. The units vested on April 21, 2015 and the award was paid out in units of the Partnership.

(4) This amount reflects the distribution of three restricted unit awards granted on April 16, 2014, of which 75,000 vested on February 1, 2015, 75,000 vested on May 29, 2015 and 150,000 vested on July 15, 2015 and the award was paid out in units of the Partnership.

(5) Reflects the value of the payout of CenterPoint Energy performance units granted in January 2012 for performance period ending December 31, 2014. Performance was based on 50% total shareholder return and 50% earnings per share, the combined achievement, as certified by CenterPoint Energy's Board, resulting in a payout of 3,765 shares of CenterPoint Energy's common stock, the cost of which was reimbursed by the Partnership.

(6) Reflects the value of the payout of CenterPoint Energy stock award granted in February 2012. The vesting of the stock award was subject to the participant's continued employment and the ability of CenterPoint Energy to declare a dividend of at least $2.43 per share over the three year period ending December 31, 2014. Awards were paid out in shares of CenterPoint Energy's common stock, the cost of which was reimbursed by the Partnership.

(7) The value of the awards were calculated based on the closing price of the Partnership's common units, as reported on the NYSE on the date of vesting.

2015 Nonqualified Deferred Compensation

Name	Executive Contributions in Last FY ($)(1)	Registrant Contributions in Last FY ($)(1)(2)	Aggregate Earnings in Last FY ($)(3)	Aggregate Withdrawals/Distributions ($)	Aggregate Balance at Last FYE ($)(2)
(a)	(b)	(c)	(d)	(e)	(f)
Peter B. Delaney	—	—	—	—	—
Deanna J. Farmer	—	5,811	(1)	—	5,810
Rodney J. Sailor	—	33,045	(858)	—	32,187
Mark C. Schroeder	—	11,827	(101)	—	11,726

Paul Weissgarber	—	12,911	(7)	—	12,904
Lynn L. Bourdon, III	—	27,655	42	27,697	—

(1) The Partnership adopted a nonqualified, deferred compensation plan in 2014. Compensation may be deferred under the plan beginning in 2015.

(2) The amounts disclosed in this column also are disclosed in the "All Other Compensation" column of the Summary Compensation Table and are further described in the All Other Compensation Table.

(3) Represents earnings on invested funds in each Executive's individual account.

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 (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

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Partnership may make company matching and annual contributions on behalf of employees whose compensation is above the Code's compensation limitation for 401(k) plans. 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 in either a lump sum or annual installment payments payable over five or ten years at the election of the applicable employee or director. 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.

Potential Payments Upon Termination or Change-in-Control

Potential Severance and Change-in-Control 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. Mr. Sailor will also be offered a change-in-control agreement that will provide a cash payment of 2.99 time 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 within two years following a change-in-control.

Severance Paid to Former Chief Executive Officer

On May 29, 2015, Lynn L. Bourdon III resigned as our President and Chief Executive Officer. In connection with his departure, Mr. Bourdon received the following pursuant to the terms of a severance agreement consistent with the severance terms agreed upon at the time of his hiring: (i) a cash payment equal to his annual salary of $600,000 plus his annual short term incentive plan award target of $600,000, (ii) the vesting of the remaining 150,000 restricted common units granted under our long-term incentive plan at the time of his hire, and (iii) the vesting of one-half of the 150,000 restricted common units granted under our long-term incentive plan in connection with our initial public offering. The separation agreement also included noncompetition and nonsolicitation restrictions for six months, as well as confidentiality and cooperation provisions. Pursuant to the cooperation provisions, Mr. Bourdon agreed to make himself reasonably available to the Partnership to respond to requests for information and to assist and cooperate in connection with legal proceedings, if any. The Partnership will pay Mr. Bourdon $250 per hour for such cooperation and assistance provided at the Partnership's request.

Severance Paid to Former Chief Commercial Officer

We are negotiating a severance agreement with Mr. Weissgarber, who resigned as Chief Commercial Officer on February 11, 2016. In addition to compensation, we anticipate that the agreement will include mutually-acceptable non-solicitation and confidentiality provisions.

Report of the Compensation Committee

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, 2015, 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 Peter B. Delaney, Alan N. Harris, C. Scott Hobbs, Peter H. Kind, William D. Rogers, Rodney J. Sailor, Scott M. Prochazka and Sean Trauschke. In addition, Stephen E. Merrill is an alternate director of Enable GP. During 2015, Gary L. Whitlock and Lynn L. Bourdon III also served as directors of Enable GP. Mr. Sailor, who also serves as President and Chief Executive Officer of Enable GP, does not receive additional compensation for his service as a director, and Mr. Bourdon, who also served as President and Chief Executive Officer of Enable GP, did not receive additional compensation

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for his services as a director. In addition, Mr. Delaney and Mr. Trauschke, who serve as the representatives of OGE Energy on the Board of Directors, Mr. Merrill, who serves as the alternate representative of OGE Energy on the Board of Directors, and Mr. Prochazka and Mr. Rogers, who serve as the representatives of CenterPoint Energy on the Board of Directors, do not receive compensation for their service as directors, and Mr. Whitlock, who served as a representative of CenterPoint Energy on the Board of Directors, did not receive compensation for his service as a director. Mr. Harris, Mr. Hobbs and Mr. Kind, our "independent directors", who are not officers or employees of Enable GP and who are not representatives of either of our sponsors, receive the compensation described below for service in 2015. In addition, Enable GP's independent directors are reimbursed for out-of-pocket expenses in connection with attending meetings of the Board of Directors and its committees. Each director is indemnified for his actions associated with being a director to the fullest extent permitted under Delaware law.

The following table sets forth the compensation earned by the independent directors of Enable GP in 2015:

Name	Fees Earned or Paid in Cash ($)(1)	Stock Awards ($)(2)	Option Awards ($)	Non-Equity Incentive Plan Compensation ($)	All Other Compensation ($)	Total ($)
Alan N. Harris	110,625	73,325	—	—	—	183,950
C. Scott Hobbs	70,000	46,660	—	—	4,216	120,876
Peter H. Kind	85,000	73,325	—	—	4,216	162,541

(1) Mr. Harris received a $70,000 annual retainer for his service as a director, a $12,500 annual retainer for his service as chairman of the Compensation Committee and a $28,125 retainer for his services as the Board of Director's lead director on the integration of the Partnership. Mr. Hobbs received a $70,000 annual retainer for his service as a director. Mr. Kind received a $70,000 annual retainer for his service as a director and a $15,000 annual retainer for his service as chairman of the Audit Committee.

(2) Reflects the aggregate grant date fair value of 2015 unit awards computed in accordance with FASB ASC Topic 718. Awards granted to independent directors vested immediately. See Note 17 to the financial statements for further information.

In February 2016, the Compensation Committee increased the annual retainer paid to each independent director to $80,000 per year, In addition, Mr. Kind as chairman of the Conflicts Committee will receive a fee of $10,000 per transaction referred to the Conflicts Committee and that the other independent directors will receive a fee of $5,000 per transaction referred to the Conflicts Committee. The increase to the annual retainer paid to each independent director will be effective March 1, 2016. The fees for the Conflicts Committee are effective January 1, 2016.

On February 16, 2016, C. Scott Hobbs informed the Board of Directors of his intent to resign as a director effective February 29, 2016. In connection with Mr. Hobbs' resignation, Mr. Hobbs will receive a one-time payment of $13,000 in recognition of his service in 2016.

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 February 1, 2016 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, subordinated units and total units beneficially owned is based on 214,541,450 common units outstanding and 207,855,430 subordinated units outstanding as of February 1, 2016.

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	Common units beneficially owned			Subordinated units beneficially owned			Common units and subordinated units beneficially owned		
Name of beneficial owner	Number	Percentage		Number	Percentage		Number	Percentage	
CenterPoint Energy, Inc.[(1)] 1111 Louisiana Houston, Texas 77002	94,151,707	22.3	%	139,704,916	33.1	%	233,856,623	55.4	%
OGE Energy Corp.[(2)] 321 North Harvey Oklahoma City, Oklahoma 73101	42,832,291	10.1	%	68,150,514	16.2	%	110,982,805	26.3	%
ArcLight Capital Partners, LLC[(3)] 200 Clarendon Street, 55th Floor Boston, Massachusetts 02117	47,777,730	11.3	%	—	—		47,777,730	11.3	%
Peter B. Delaney[(4)]	25,000	*		—	—		25,000	*	
Alan N. Harris[(4)]	33,930	*		—	—		33,930	*	
C. Scott Hobbs[(4)]	27,555	*		—	—		27,555	*	
Peter H. Kind[(4)]	13,953	*		—	—		13,953	*	
John P. Laws[(4)]	9,664	*		—	—		9,664	*	
Scott M. Prochazka[(5)]	10,000	*		—	—		10,000	*	
William D. Rogers[(5)]	—	*		—	—		—	*	
Sean Trauschke[(6)]	2,500	*		—	—		2,500	*	
Paul Brewer[(4)]	4,293	*		—	—		4,293	*	
Deanna J. Farmer[(4)]	20,087	*		—	—		20,087	*	
Stephen E. Merrill[(6)]	—	*		—	—		—	*	
Rodney J. Sailor[(4)]	153,199	*		—	—		153,199	*	
Mark C. Schroeder[(4)]	—	*		—	—		—	*	
Paul Weissgarber[(4)(7)]	45,230	*		—	—		45,230	*	
All directors and executive officers as a group (14 people)	345,411	*		—	—		345,411	*	

*Less than 1%

(1) Based on a Schedule 13D/A filed with the SEC pursuant to the Exchange Act on February 1, 2016. The common units and subordinated units reported represent the aggregated beneficial ownership by CenterPoint Energy, Inc., together with its wholly owned subsidiaries. CenterPoint Energy, Inc. may be deemed to have sole voting power with respect to 233,856,623 common units and subordinated units. CenterPoint Energy, Inc. has no shared voting or dispositive power with respect to any of the common units or subordinated units shown. On January 28, 2016, the Partnership entered into an agreement with CenterPoint Energy, Inc. to issue and sell in a Private Placement an aggregate of 14,520,000 Preferred Units. The Private Placement is expected to close prior to the end of the first quarter of 2016, subject to certain closing conditions. For a further discussion regarding the Private Placement, see Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operation - Liquidity and Capital Resources - Equity Issuances."

(2) 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 and subordinated units. OGE Energy Corp. has no shared voting or dispositive power with respect to any of the common units or subordinated units shown.

(3)

Based on a Schedule 13G filed with the SEC pursuant to the Exchange Act on February 17, 2015. ArcLight Capital Partners, LLC is the investment advisor for, and ArcLight Capital Holdings, LLC is the managing partner of the general partner of ArcLight Energy Partners Fund V, L.P. and ArcLight Energy Partners Fund IV, L.P. ArcLight Capital Holding, LLC is the sole member of the general partner of Bronco Midstream Partners, L.P. The common units reported herein are held by Enogex Holdings and Bronco Midstream Infrastructure LLC. ArcLight Energy Partners Fund V, L.P., ArcLight Energy Partners Fund IV, L.P. and Bronco Midstream Partners, L.P. have monetary interests in the common units. Bronco Midstream Infrastructure, LLC may be deemed to have shared voting and dispositive power with respect to 43,585,926 common units. Each of Enogex Holdings LLC, ArcLight Capital Partners, LLC, ArcLight Capital Holdings, LLC, ArcLight Energy Partners Fund V, L.P., ArcLight Energy Partners Fund IV, L.P., Bronco Midstream Partners, L.P. and

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Daniel R. Revers may be deemed to have shared voting and dispositive power with respect to 47,777,730 common units. Each of the foregoing entities disclaims beneficial ownership except to the extent of their monetary interest therein.
(4) One Leadership Square, 211 North Robinson Avenue, Suite 150, Oklahoma City, Oklahoma 73102
(5) 1111 Louisiana Street, Houston, Texas 77002
(6) 321 North Harvey, P.O. Box 321, Oklahoma City, Oklahoma 73101
(7) These units were forfeited upon Mr. Weissgarber's resignation on February 11, 2016.

Beneficial Ownership of General Partner Interest

CenterPoint Energy and OGE Energy collectively own our general partner and 136,983,998 common units and 207,855,430 subordinated units representing an aggregate 81.7% limited partner interest in us. In addition, 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]	—	—	11,054,681

(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.
(2) The number of securities remaining available for future issuance includes 581,772 restricted units that have been granted under our long-term incentive plan that have not vested.

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

CenterPoint Energy and OGE Energy own 136,983,998 common units and 207,855,430 subordinated units representing an aggregate 81.7% limited partner interest in us. In addition, CenterPoint Energy owns a 50% management interest and a 40% economic interest and OGE owns a 50% management interest and a 60% economic interest in Enable GP, our general partner. Enable GP owns a non-economic general partner interest in us and all of our incentive distribution rights.

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 136,983,998 common units and all of the subordinated units. 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, OGE Energy and ArcLight

Acquisition of CenterPoint Energy Interests in SESH

For the period May 1, 2013 through May 29, 2014, CenterPoint Energy indirectly owned a 25.05% interest in SESH. Pursuant to the MFA, that interest could be contributed to the Partnership upon exercise of certain put or call rights, under which CenterPoint Energy would contribute to the Partnership CenterPoint Energy’s retained interest in SESH at a price equal to the fair market value of such interest at the time the put right or call right is exercised. On May 13, 2014, CenterPoint Energy exercised its put right with respect to a 24.95% interest in SESH. Pursuant to the put right, on May 30, 2014, CenterPoint Energy contributed a 24.95% interest in SESH to the Partnership in exchange for 6,322,457 common units representing limited partner interests in the Partnership, which had a fair value of $161 million based upon the closing market price of the Partnership's common units. On June 12, 2015, CenterPoint Energy exercised its remaining put right with respect to a 0.1% interest in SESH. Pursuant to the put right, on June 30, 2015, CenterPoint Energy contributed its remaining 0.1% interest in SESH to the Partnership in exchange for 25,341 common units representing limited partner interests in the Partnership, which had a fair value of $1 million based upon the closing market price of the Partnership's common units. As of December 31, 2015, the Partnership owns a 50% interest in SESH, and Spectra Energy Partners, LP owns the remaining 50% in SESH.

Our rights in connection with the interest in SESH retained by CenterPoint Energy, including with respect to the determination of fair market value of the SESH interest, will be exercised by the directors of our general partner appointed by OGE Energy. Please read Item 1A. “Risk Factors-Risks Related to Our Business-Under certain circumstances, affiliates of Spectra Energy Corp will have the right to purchase an ownership interest in SESH at fair market value.”

Notes payable—affiliated companies

The Partnership has outstanding long-term notes payable—affiliated companies to CenterPoint Energy at both December 31, 2015 and 2014 of $363 million which mature in 2017. Notes having an aggregate principal amount of approximately $273 million bear a fixed interest rate of 2.10% and notes having an aggregate principal amount of approximately $90 million bear a fixed interest rate of 2.45%. The Partnership intends to redeem these notes in connection with the closing of the Private Placement. For a further discussion regarding the Private Placement, see Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operation—Liquidity and Capital Resources - Equity Issuances."

Registration Rights in Connection with Private Placement

The Partnership has agreed to enter into a Registration Rights Agreement with CenterPoint Energy at the closing of the Private Placement, pursuant to which, among other things, the Partnership will give CenterPoint Energy certain rights to require

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the Partnership to file and maintain a registration statement with respect to the resale of the Preferred Units and any other series of preferred units or common units representing limited partnership interests in the Partnership that are issuable upon conversion of the Preferred Units.

Services Agreements

We are a party to services agreements with each of CenterPoint Energy and OGE Energy pursuant to which they perform certain administrative services for us that are generally consistent with the level and type of services they provided to each of their respective businesses prior to our formation. These services include accounting, finance, legal, risk management, information technology and human resources. 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. For the year ended December 31, 2015, we reimbursed $11 million and $15 million to CenterPoint Energy and OGE Energy, respectively, pursuant to the services agreements. The initial term of the services agreements ends in May 2016, after which date they continue on a year-to-year basis unless terminated by us upon 90 days' notice. We may terminate each services agreement, or the provision of any services thereunder, upon approval by the Board of Directors and 180 days' notice to CenterPoint Energy and OGE Energy, as applicable; provided, however, that the services agreement with OGE Energy and the provision of payroll and benefit administration services by OGE Energy thereunder may not be terminated prior to the termination of the transitional seconding agreement between the Partnership and OGE Energy.

Omnibus Agreement

We are a party to an omnibus agreement with CenterPoint Energy, OGE Energy and ArcLight that addresses competition and indemnification matters.

Competition

Subject to the exceptions described below, each of CenterPoint Energy and OGE Energy is required to hold or otherwise conduct all of its respective midstream operations located within the United States through us. This requirement will cease to apply to both CenterPoint Energy and OGE Energy as soon as either CenterPoint Energy or OGE Energy cease to hold 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), to the extent such activities are located within the United States.

If CenterPoint Energy or OGE Energy intends to cease using the assets of such restricted business within 12 months of the acquisition of such business, then the restrictions discussed immediately above do not apply; provided, however, that CenterPoint Energy or OGE Energy, as applicable, must notify us following completion of such acquisition.

In addition, if CenterPoint Energy or OGE Energy acquires any assets or equity of any person engaged in midstream operations with such midstream operations having a value in excess of $50 million (or $100 million in the aggregate with such party's other acquired midstream operations that have not been offered to us), the acquiring party will be required to offer to us the opportunity to acquire such assets or equity for such value; however, the acquiring party will not be obligated to offer any such assets or equity to us if the acquiring party intends to cease using them in midstream operations within 12 months of their acquisition. If we do not exercise this option then the acquiring party will be free to retain and operate such midstream operations; however, if the fair market value of such midstream operations is greater than 66 2/3% of the fair market value of all of the assets being acquired in such transaction, then the acquiring party must use commercially reasonable efforts to dispose of such midstream operations within 24 months from the date on which our option to purchase has expired.

Indemnification

Under the omnibus agreement, CenterPoint Energy and OGE Energy are obligated to indemnify us for specified breaches of representations and warranties in the master formation agreement pursuant to which we were formed related to:

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- their authority to enter into the transactions that formed us and the capitalization of the entities contributed to us;
- permits related to the operation of the assets contributed to us;
- compliance with environmental laws;
- title to properties and rights of way;
- the tax classification of the entities contributed to us;
- indemnified taxes; and
- events and conditions associated with their ownership and operation of the contributed assets.

An affiliate of ArcLight is obligated to indemnify us with respect to the first bullet point above and shares an indemnification obligation with OGE Energy with respect to the sixth and seventh bullet points above.

CenterPoint Energy’s and OGE Energy’s maximum liability for this indemnification obligation with respect to permit, environmental and title representations will not exceed $250 million, and neither CenterPoint Energy nor OGE Energy will have any obligation under this indemnification until our aggregate indemnifiable losses exceed $25 million.

CenterPoint Energy’s and OGE Energy’s indemnification obligations for permit matters expired on May 1, 2014. Indemnification obligations for environmental and title and rights of way matters will survive until May 1, 2016 and for tax classification matters and indemnified taxes will survive until 30 days following the expiration of the applicable statute of limitations. Indemnification for authority and capitalization matters survives indefinitely.

Names and Insignia and Other Matters

The omnibus agreement also addresses our use of certain names and insignia. We have agreed not to use or otherwise exploit any service marks, trade names, logos or similar property including the words “CenterPoint Energy,” “OGE” or “Enogex.” We have also agreed to use commercially reasonable efforts to remove such names and insignia from our assets.

Registration Rights Agreement

Pursuant to a registration rights agreement we entered into with affiliates of CenterPoint Energy, OGE Energy and ArcLight, those affiliates have specified demand and piggyback registration rights with respect to the registration and sale of their common units. Affiliates of CenterPoint Energy, OGE Energy and ArcLight each have the right to cause us to prepare and file a registration statement with the SEC covering the offering and sale of their common units. We are not obligated to effect more than (i) three such demand registrations for CenterPoint Energy and OGE Energy combined, or (ii) two such demand registrations (and no more than one in any twelve-month period) for ArcLight. If we propose to file a registration statement (other than pursuant to a demand registration discussed above, or other than for an employee benefit plan), CenterPoint Energy, OGE Energy and/or ArcLight may request to “piggyback” onto such registration statement in order to offer and sell their common units. We have agreed to pay all registration expenses in connection with such demand and piggyback registrations. Registration expenses do not include underwriters’ compensation, stock transfer taxes or counsel fees.

Employee Agreements

In May 2013,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, pursuant to which they have 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 will 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. The Partnership’s reimbursement of OGE Energy for employee costs arising out of OGE Energy’s defined benefit and retiree medical plans is fixed at $6 million in each of 2015 and 2016, $5 million in 2017, and at actual cost subject to a cap of $5 million in 2018 and thereafter, in the event of continued secondment.

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Tax Sharing Agreements

We are parties to a tax sharing agreement with CenterPoint Energy, OGE Energy and Enable GP pursuant to which we have agreed to reimburse them for state income and franchise taxes attributable to our activity (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

Transportation and Storage Agreement with OG&E

EOIT provides no-notice load-following transportation and storage services to OG&E. On March 17, 2014, EOIT executed a new transportation agreement with OG&E effective May 1, 2014, with a primary term through April 30, 2019. Following the primary term, the agreement will remain in effect from year to year thereafter unless either party provides notice of termination to the other party at least 180 days prior to the commencement of the succeeding annual period. For the year ended December 31, 2015, we recorded revenues from OG&E of $35 million for transportation services and $4 million for natural gas storage services.

Transportation and Storage Agreements with CenterPoint Energy

EGT provides the following services to CenterPoint Energy’s LDCs in Arkansas, Louisiana, Oklahoma, and Northeast Texas: (1) firm transportation with seasonal contract demand, (2) firm storage, (3) no notice transportation with associated storage, and (4) maximum rate firm transportation. The first three services are in effect through March 31, 2021, and will remain in effect from year to year thereafter unless either party provides 180 days’ written notice prior to the contract termination date. The maximum rate firm transportation is in effect through March 31, 2018.

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

MRT provides firm transportation and firm storage services to CenterPoint Energy under agreements that are in effect through May 15, 2018, but will continue year to year thereafter unless either party provides twelve months' written notice prior to the contract termination date.

For the year ended December 31, 2015, revenues from our firm interstate natural gas transportation and storage contracts attributable to CenterPoint Energy were $110 million.

Gas Sales and Purchases Transactions

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, 2015, we recorded revenues of $7 million from gas sales to CenterPoint Energy, cost of natural gas and natural gas liquids sold of $2 million from gas purchases from CenterPoint Energy and revenues of $8 million from gas sales to OGE Energy.

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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 EGT and MRT to enter into transportation and storage agreements with CenterPoint Energy and OGE Energy and their respective affiliates provided that our general counsel determines that those agreements have been entered into in compliance the Natural Gas Act. In providing transportation and storage services, EGT and MRT are subject to regulation by the Federal Energy Regulatory Commission under the Natural Gas Act. The Natural Gas Act prohibits both making or grant any undue preference or advantage and maintaining any unreasonable difference in rates, charges, services, facilities, or in any other respect. As a result, our Board of Directors believes that any transportation or storage agreements entered into by EGT and MRT in compliance with the Natural Gas Act are on term no less favorable to us than those generally provided to or available from unrelated third parties entering into similar transactions.

Many of the related party transactions policy described above were entered into prior to the closing of our initial public offering 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 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

The NYSE does not require a listed publicly traded partnership, such as ours, to have a majority of independent directors on the Board of Directors. For a discussion of the independence of the Board of Directors, please see "Item 10. Directors, Executive Officers and Corporate Governance-Management of the Partnership."

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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:

	2015	2014
	(In thousands)	
Audit fees	$1,132	$1,132
Audit-related fees	116	137
Tax	433	141
Total	$1,681	$1,410

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

Audit-related fees for the years ended December 31, 2015 and 2014, include fees associated 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 relate to the two tax years ended December 31, 2013 and December 31, 2014.

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 independent registered public accounting firm to conduct the audit of the Partnership's consolidated financial statements for the year ended December 31, 2015.

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.

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(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	Second Amended and Restated Agreement of Limited Partnership of Enable Midstream Partners, LP	Registrant's Form 8-K filed April 22,2014	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
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

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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 June 18, 2015 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, The Bank of Tokyo-Mitsubishi UFJ, 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 BTM, 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 5-year unsecured revolving credit facility.	Registrant's Form 10-Q filed June 19, 2015	File No. 001-36413	Exhibit 10.1
10.18*	Separation and Release Agreement dated July 15, 2015 among Enable Midstream Partners, LP, Enable Midstream Services, LLC, and Lynn L. Bourdon III	Registrant's Form 8-K filed July 17, 2015	File No. 001-36413	Exhibit 99.1
10.19	Term Loan Agreement dated July 31, 2015 by and among Enable Midstream Partners, LP and Bank of America, N.A., as administrative agent, Merrill Lynch, Pierce, Fenner & Smith Incorporated, as sole lead arranger and sole bookrunner, Mizuho Bank, Ltd., as syndication agent and as documentation agent, and the several lenders from time to time party thereto relating to a 3-year $450 million unsecured term loan facility.	Registrant's Form 8-K filed November 4, 2015	File No. 001-36413	Exhibit 10.1
+10.20*	Employment Agreement Letter dated November 30, 2015 by and between Enable Midstream Services, LLC and Peter B. Delaney			
+10.21*	Enable Midstream Partners Deferred Compensation Plan effective January 1, 2015			
+10.22*	Enable Midstream Partners Deferred Compensation Plan Adoption Agreement effective January 1, 2015			
+10.23*	Second Amendment to Enable Midstream Partners, LP Short Term Incentive Plan Effective February 16, 2016			
+10.24*				

	Enable Midstream Partners, LP Long Term Incentive Plan Annual Performance Unit Award Agreement for Senior Officers
+10.25*	Enable Midstream Partners, LP Long Term Incentive Plan Annual Phantom Unit Award Agreement for Senior Officers
+12.1	Computation of ratio of earnings to fixed charges
+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.

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.

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SIGNATURE

Pursuant to the requirements of the Securities 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 17, 2016	By: /s/ Tom Levescy Tom Levescy Chief Accounting Officer and Controller (Principal Accounting Officer)

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Pursuant to the requirements of the Securities 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 (Principal Executive Officer)	February 17, 2016
/s/ John P. Laws John P. Laws	Executive Vice President, Chief Financial Officer, and Treasurer (Principal Financial Officer)	February 17, 2016
/s/ Tom Levescy Tom Levescy	Chief Accounting Officer and Controller (Principal Accounting Officer)	February 17, 2016
/s/ Peter B. Delaney Peter B. Delaney	Director	February 17, 2016
/s/ Alan N. Harris Alan N. Harris	Director	February 17, 2016
/s/ C. Scott Hobbs C. Scott Hobbs	Director	February 17, 2016
/s/ Peter H. Kind Peter H. Kind	Director	February 17, 2016
/s/ Scott M. Prochazka Scott M. Prochazka	Director	February 17, 2016
/s/ William D. Rogers William D. Rogers	Director	February 17, 2016
/s/ Sean Trauschke Sean Trauschke	Director	February 17, 2016