UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
Form 10-K

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

For the fiscal year ended December 31, 2017

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 number: 001-36340

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

Delaware	**16-1616605**
(State of organization)	(I.R.S. Employer Identification No.)
1722 Routh St., Suite 1300	
Dallas, Texas	**75201**
(Address of principal executive offices)	(Zip Code)

(214) 953-9500
(Registrant's telephone number, including area code)

SECURITIES REGISTERED PURSUANT TO SECTION 12(b) OF THE ACT:

Title of Each Class	Name of Exchange on which Registered
Common Units Representing Limited Partnership Interests	The New York Stock Exchange

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

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

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

Indicate by check mark whether registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ☒ 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 the registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☐

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

Large accelerated filer ☒	Accelerated filer ☐
Non-accelerated filer ☐ (Do not check if a smaller reporting company)	Smaller reporting company ☐
Emerging growth company ☐	

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ☐

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

The aggregate market value of the common units representing limited partner interests held by non-affiliates of the registrant was approximately $2.8 billion on June 30, 2017, based on $16.96 per unit, the closing price of the common units as reported on the New York Stock Exchange on such date.

At February 14, 2018, there were 350,022,931 common units outstanding.

DOCUMENTS INCORPORATED BY REFERENCE:
None.

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Definitions

The following terms as defined generally are used in the energy industry and in this document:

/d = per day
Bbls = barrels
Bcf = billion cubic feet
CO_2= Carbon dioxide
CPI= Consumer Price Index
HP = horsepower
MMBtu = million British thermal units
MMcf = million cubic feet
NGL = natural gas liquid

Capacity volumes for our facilities are measured based on physical volume and stated in cubic feet ("Bcf", "Mcf" or "MMcf"). Throughput volumes are measured based on energy content and stated in British thermal units ("Btu" or "MMBtu"). A volume of capacity of 100 MMcf correlates to an approximate energy content of 100,000 MMBtu, although this correlation will vary depending on the composition of natural gas and is typically higher for unprocessed gas, which contains a higher concentration of NGLs. Fractionated volumes are measured based on physical volumes and stated in gallons. Crude oil, condensate and brine services volumes are measured based on physical volume and stated in barrels ("Bbls").

We define "gross operating margin," a non-GAAP financial measure, as revenues less cost of sales. We disclose gross operating margin in addition to total revenue because it is the primary performance measure used by our management. We believe gross operating margin is an important measure because, in general, our business is to purchase and resell natural gas, NGLs, condensate and crude oil for a margin and to gather, process, store, transport or market natural gas, NGLs, condensate and crude oil for a fee. The GAAP measure most directly comparable to gross operating margin is operating income (loss). For more information on gross operating margin, including its limitations as a financial measure, see "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Non-GAAP Financial Measures."

ENLINK MIDSTREAM PARTNERS, LP

PART I

Item 1. Business

General

EnLink Midstream Partners, LP is a publicly traded Delaware limited partnership formed in 2002. Our common units are traded on the New York Stock Exchange (“NYSE”) under the symbol “ENLK.” Our business activities are conducted through our subsidiary, EnLink Midstream Operating, LP, a Delaware limited partnership (the “Operating Partnership”), and the subsidiaries of the Operating Partnership. Our executive offices are located at 1722 Routh Street, Suite 1300, Dallas, Texas 75201, and our telephone number is (214) 953-9500. Our Internet address is www.enlink.com. We post the following filings in the “Investors” section of our website as soon as reasonably practicable after they are electronically filed with or furnished to the Securities and Exchange Commission (“SEC”): our Annual Reports on Form 10-K; our quarterly reports on Form 10-Q; our current reports on Form 8-K; and any amendments to those reports or statements filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended. All such filings on our website are available free of charge. In this report, the terms “Partnership,” “ENLK” and “Registrant,” as well as the terms “our,” “we,” “us” and “its,” are sometimes used as abbreviated references to EnLink Midstream Partners, LP itself or EnLink Midstream Partners, LP together with its consolidated subsidiaries, including the Operating Partnership.

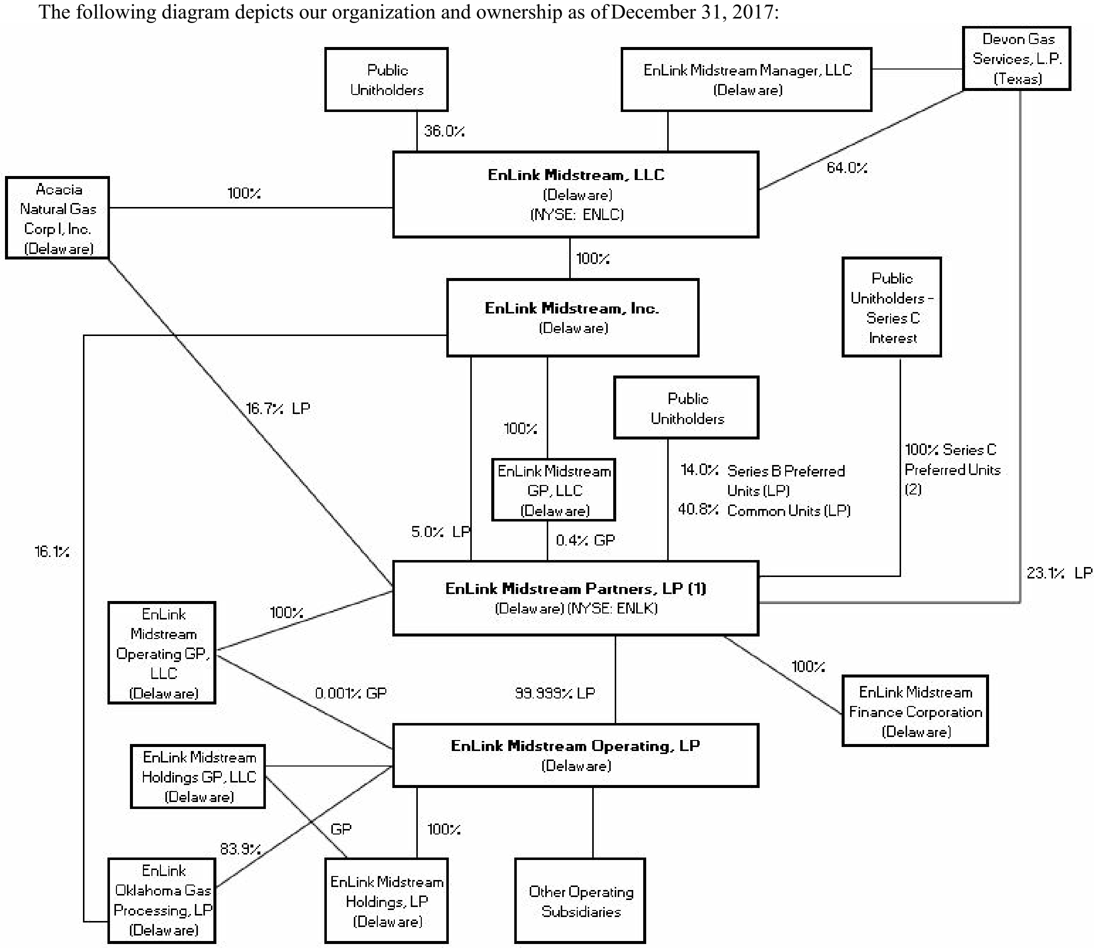
EnLink Midstream GP, LLC, a Delaware limited liability company, is our general partner. Our general partner manages our operations and activities. Our general partner is an indirect, wholly-owned subsidiary of EnLink Midstream, LLC (“ENLC” or “EnLink Midstream”). ENLC’s units are traded on the NYSE under the symbol “ENLC.” ENLC’s manager is an indirect, wholly-owned subsidiary of Devon Energy Corporation (“Devon”).

Effective as of March 7, 2014, the Operating Partnership acquired (the “Acquisition”) 50% of the outstanding equity interests in EnLink Midstream Holdings, LP (“Midstream Holdings”) and all of the outstanding equity interests in EnLink Midstream Holdings GP, LLC, the general partner of Midstream Holdings, in exchange for the issuance by us of 120,542,441 units representing a new class of limited partnership interests in our partnership. At the same time, EnLink Midstream, Inc. (“EMI”), the entity that directly owns our general partner, became a wholly-owned subsidiary of ENLC (together with the Acquisition, the “Business Combination”). At the conclusion of the Business Combination, another wholly-owned subsidiary of ENLC, Acacia Natural Gas Corp. I, Inc. (“Acacia”), owned the remaining 50% of the outstanding equity interests in Midstream Holdings. In 2015, Acacia contributed the remaining 50% interest in Midstream Holdings to us in exchange for 68.2 million units of our limited partnership interests in two separate drop down transactions, with 25% contributed in February 2015 and 25% contributed in May 2015 (the “EMH Drop Downs”). After giving effect to the EMH Drop Downs, we own 100% of Midstream Holdings.

Midstream Holdings was formerly a wholly-owned subsidiary of Devon, and it gathers, processes and transports natural gas, primarily for Devon. Midstream Holdings also fractionates NGLs into component NGL products. Under the acquisition method of accounting, Midstream Holdings is considered the historical predecessor of our business because Devon obtained control of us through its control of ENLC and through the indirect acquisition of our general partner.

On January 7, 2016, EnLink Oklahoma Gas Processing, LP (“EnLink Oklahoma T.O.”), an indirect subsidiary of ENLK, completed its acquisition of 100% of the issued and outstanding membership interests of TOMPC LLC and TOM-STACK, LLC. EnLink Oklahoma T.O. is sometimes used herein to refer to EnLink Oklahoma Gas Processing, LP itself or EnLink Oklahoma Gas Processing, LP, together with its consolidated subsidiaries. As a result of the acquisition, the Operating Partnership owns an 83.9% limited partnership interest in EnLink Oklahoma T.O., and EMI owns a 16.1% limited partnership interest in EnLink Oklahoma T.O. In addition, EnLink Energy GP, LLC, the general partner of EnLink Oklahoma T.O. and an indirect subsidiary of our partnership, owns the non-economic general partnership interest.

The following diagram depicts our organization and ownership as of December 31, 2017:



(1) The general partner ("GP") ownership percentage for EnLink Midstream Partners, LP accounts for general partner units, while the limited partner ("LP") ownership percentages for EnLink Midstream Partners, LP account for ENLK common units and Series B Preferred Units (as defined below), which are convertible into ENLK common units on a one-for-one basis, subject to certain adjustments.

(2) Series C Preferred Units (as defined below) are perpetual preferred units that are not convertible into ENLK common units, and therefore, are not factored into the EnLink Midstream Partners, LP ownership calculations for the limited partner and general partner ownership percentages presented.

Our Operations

We primarily focus on providing midstream energy services, including:

- gathering, compressing, treating, processing, transporting, storing and selling natural gas;
- fractionating, transporting, storing, exporting and selling NGLs; and
- gathering, transporting, stabilizing, storing, trans-loading and selling crude oil and condensate.

Our midstream energy asset network includes approximately 11,000 miles of pipelines, 20 natural gas processing plants with approximately 4.8 Bcf/d of processing capacity, 7 fractionators with approximately 260,000 Bbls/d of fractionation capacity, barge and rail terminals, product storage facilities, purchasing and marketing capabilities, brine disposal wells, a crude oil trucking fleet, and equity investments in certain joint ventures. Our operations are based in the United States, and our sales are derived primarily from domestic customers.

We connect the wells of producers in our market areas to our gathering systems, which consist of networks of pipelines that collect natural gas from points near producing wells and transport it to our processing plants or to larger pipelines for further transmission. We operate processing plants that remove NGLs from the natural gas stream that is transported to the processing plants by our own gathering systems or by third-party pipelines. In conjunction with our gathering and processing business, we may purchase natural gas and NGLs from producers and other supply sources and sell that natural gas or NGLs to utilities, industrial consumers, other markets and pipelines. Our transmission pipelines receive natural gas from our gathering systems and from third-party gathering and transmission systems and deliver natural gas to industrial end-users, utilities and other pipelines.

Our fractionators separate NGLs into separate purity products, including ethane, propane, iso-butane, normal butane and natural gasoline. Our fractionators receive NGLs primarily through our transmission lines that transport NGLs from East Texas and from our South Louisiana processing plants, and our fractionators also have the capability to receive NGLs by truck or rail terminals. We also have agreements pursuant to which third parties transport NGLs from our West Texas and Central Oklahoma operations to our NGL transmission lines that then transport the NGLs to our fractionators. In addition, we have NGL storage capacity to provide storage for customers.

Our crude oil and condensate business includes gathering and transmission via pipelines, barges, rail and trucks, condensate stabilization and brine disposal. We may purchase crude oil and condensate from producers and other supply sources and sell that crude oil and condensate through our terminal facilities that provide market access.

Across our businesses, we primarily earn our fees through various fee-based contractual arrangements, which include stated fee-only contract arrangements or arrangements with fee-based components where we purchase and resell commodities in connection with providing the related service and earn a net margin as our fee. We earn our net margin under our purchase and resell contract arrangements primarily as a result of stated service-related fees that are deducted from the price of the commodities purchased. While our transactions vary in form, the essential element of each transaction is the use of our assets to transport a product or provide a processed product to an end-user or other marketer or pipeline at the tailgate of the plant, barge terminal or pipeline.

Our assets are included in five primary segments:

- *Texas Segment.* The Texas segment includes our natural gas gathering, processing and transmission operations in North Texas and the Midland and Delaware Basins (together, the “Permian Basin”) in West Texas;

- *Oklahoma Segment*. The Oklahoma segment includes our natural gas gathering, processing and transmission activities in Cana-Woodford, Arkoma-Woodford, Northern Oklahoma Woodford, Sooner Trend Anadarko Basin Canadian and Kingfisher Counties (“STACK”) and Central Northern Oklahoma Woodford (“CNOW”) shale areas;

- *Louisiana Segment*. The Louisiana segment includes our natural gas pipelines, natural gas processing plants, gas and NGL storage facilities, fractionation facilities and NGL pipelines located in Louisiana;

- *Crude and Condensate Segment.* The Crude and Condensate segment includes our crude oil operations in the Permian Basin and Central Oklahoma, our Ohio River Valley (“ORV”) crude oil, condensate stabilization, natural gas compression and brine disposal activities in the Utica and Marcellus Shales and our crude oil activities associated with our Victoria Express Pipeline and related truck terminal and storage assets (“VEX”) located in the Eagle Ford Shale; and

- *Corporate Segment*. The Corporate segment includes our unconsolidated affiliate investments in the Cedar Cove joint venture (“Cedar Cove JV”) in Oklahoma, our contractual right to the economic benefits and burdens associated with Devon’s 38.75% ownership interest in Gulf Coast Fractionators (“GCF”) and our general corporate property and expenses.

For more information about our segment reporting, see “Item 8. Financial Statements and Supplementary Data—Note 15.”

About Devon

Devon (NYSE: DVN) is a leading independent energy company engaged primarily in the exploration, development and production of crude oil, natural gas and NGLs. Devon's operations are concentrated in various onshore areas in the U.S. and Canada. Please see Devon's Annual Report on Form 10-K for the year ended December 31, 2017 (the "Devon Annual Report") for additional information concerning Devon's business. The information contained in the Devon Annual Report is not incorporated by reference into this Annual Report on Form 10-K and should not be considered part of this or any other report that we file with or furnish to the SEC.

Our Business Strategies

Our primary business objective is to provide cash flow stability in our business while growing prudently and profitably. We intend to accomplish this objective by executing the following strategies:

- *Execute in our core growth areas.* We believe our assets are positioned in some of the most economically advantageous basins in the U.S., as well as key demand centers with growing end-use customers. We expect to grow certain of our systems organically over time by meeting our customers' midstream service needs that result from their drilling activity in our areas of operation or growth in supply needs. We continually evaluate economically attractive organic expansion opportunities in our areas of operation that allow us to leverage our existing infrastructure, operating expertise and customer relationships by constructing and expanding systems to meet new or increased demand for our services.

- *Maintain a strong financial position.* We believe that maintaining a conservative and balanced capital structure, appropriate leverage and other key financial metrics will afford us better access to the capital markets at a competitive cost of capital. We also believe a strong financial position provides us the opportunity to grow our business in a prudent manner throughout the cycles in our industry.

- *Maintain stable cash flows supported by long-term, fee-based contracts.* We will seek to generate cash flows pursuant to long-term, firm contracts with creditworthy customers. We will continue to pursue opportunities to increase the fee-based components of our contract portfolio to minimize our direct commodity price exposure.

Our Competitive Strengths

We believe that we are well-positioned to execute our strategies and to achieve our primary business objective due to the following competitive strengths:

- *Devon's sponsorship*. We expect our relationship with Devon will continue to provide us with significant business opportunities. Devon is one of the largest independent oil and gas producers in North America. Devon has a significant interest in promoting the success of our business, due to its 64.0% direct ownership interest in ENLC and 23.1% direct ownership interest in ENLK as of December 31, 2017. Approximately 46.8% of our gross operating margin for the year ended December 31, 2017 was attributable to commercial contracts with Devon.

- *Strategically-located assets*. The majority of our assets are strategically located in economically advantageous regions with the potential for increasing throughput volume and cash flow generation. Our asset portfolio includes gathering, transmission, fractionation, and processing systems that are located in the areas in which producer activity is focused on crude oil, condensate and NGLs, as well as natural gas. We have established platforms in Texas, Oklahoma and Louisiana, and we are focused on growing our operations in Central Oklahoma, the Permian Basin and southern Louisiana through organic development and acquisitions.

- *Stable cash flows.* Approximately 94% of our gross operating margin for the year ended December 31, 2017 was generated from fee-based contract arrangements with minimal direct commodity price exposure. In addition, our cash flows are generated across a variety of products, services and geographic locations and through transactions with a strong portfolio of customers with investment-grade credit ratings. We have approximately six years remaining on fixed-fee gathering and processing agreements with a subsidiary of Devon pursuant to which we provide gathering, treating, compression, dehydration, stabilization, processing and fractionation services, as applicable, for natural gas delivered by Devon to our gathering and processing systems in the Barnett and Cana-Woodford Shales. These agreements provide us with dedication of all of the natural gas owned or controlled by Devon and produced from or attributable to existing and future wells located on certain oil, natural gas and mineral leases covering lands within the acreage dedications, excluding properties previously dedicated to other natural gas gathering systems not owned and operated by Devon. These agreements also include minimum volume commitments ("MVCs") that will remain in effect up to January 1, 2019. Additionally, our EnLink Oklahoma T.O. assets are supported by Devon with acreage dedications and MVCs for gathering and processing on Devon's STACK acreage through 2021. For additional information, please read "Our Contractual Relationship with Devon." We will continue to focus on contract structures that reduce volatility and support long-term stability of cash flows.

- *Integrated midstream services*. We span the energy value chain by providing natural gas, NGL, crude oil and condensate services across a diverse customer base. These services include gathering, compressing, treating, processing, transporting, storing and selling natural gas, fractionating, transporting, storing, exporting and selling NGLs, and gathering, transporting, stabilizing, storing and trans-loading crude oil and condensate. We believe our ability to provide all of these services gives us an advantage in competing for new opportunities because we can provide substantially all services that producers, marketers and others require to move natural gas, NGLs, crude oil and condensate from the wellhead to the market on a cost-effective basis.

- *Experienced management team.* Our management team has deep experience in the energy industry and has a proven track record of creating value through the development, acquisition, optimization and integration of midstream assets. We believe this team provides us with a strong foundation for evaluating growth opportunities and operating our assets in a safe, reliable and efficient manner.

We believe that we will leverage our competitive strengths to successfully implement our strategy; however, our business involves numerous risks and uncertainties that may prevent us from achieving our primary business objectives. For a more complete description of the risks associated with our business, please see "Item 1A. Risk Factors."

Our Contractual Relationship with Devon

The following table includes our long-term, fixed-fee contracts with Devon:

Contract	Remaining Contract Term (Years)	Year Contract Entered Into	Gathering MVC (MMcf/d)	Processing MVC (MMcf/d)	Remaining MVC Term (Years)	Annual Rate Escalators
Bridgeport gathering and processing contract	6	2014	850	650	1	CPI
Johnson County gathering contract	6	2014	125	—	1	CPI
Cana gathering and processing contract	6	2014	330	330	1	CPI
EnLink Oklahoma T.O. gathering and processing contract (1)	12	2016	Varies	Varies	3	—

(1) The gathering MVCs and processing MVCs under this contract escalate on a quarterly basis over the life of the five-year commitment, beginning with an average commitment of 37 MMcf/d during 2016 and ending with an average commitment of 230 MMcf/d during 2020.

In addition, we entered into to a five-year transportation MVC, which was executed in June 2014 and expires in July 2019, with Devon related to VEX. The MVC under the VEX contract averaged 25,000 Bbls/d during the first year and will average 30,000 Bbls/d for years two through five.

Recent Growth Developments

Organic Growth

Central Oklahoma Plants. In 2017, we completed construction of two new cryogenic gas processing plants, which included the Chisholm II plant completed in April 2017 and the Chisholm III plant completed in December 2017. Each plant provides 200 MMcf/d of processing capacity and is connected to new and existing gathering pipeline and compression assets in the STACK play in Oklahoma. The new capacity is supported by new and existing long-term contracts.

In addition, we are constructing an additional 200 MMcf/d gas processing plant, referred to as the "Thunderbird plant" to expand our Central Oklahoma processing capacity. We expect to begin operations on the Thunderbird plant during the first quarter of 2019.

In June 2017, we entered into a long-term, fee-based arrangement with Oneok Partners ("Oneok") under which Oneok transports NGLs from our Chisholm processing facility to the Gulf Coast and our Cajun-Sibon system. The agreement allows us to retain control of volumes and preferentially fill our Cajun-Sibon system.

Black Coyote Crude Oil Gathering System. In the fourth quarter of 2017, we began construction of a new crude oil gathering system that we refer to as "Black Coyote," which will expand our operations in the core of the STACK play in Central Oklahoma. Black Coyote is being built primarily on acreage dedicated from Devon, which will be the main shipper on the system. The system is expected to be operational in the first quarter of 2018.

Lobo Natural Gas Gathering and Processing Facilities. The Lobo facilities are part of our joint venture (the "Delaware Basin JV") with an affiliate of NGP Natural Resources XI, LP ("NGP") and are supported by long-term contracts. In the first quarter of 2017, we completed the expansion of a 75-mile gathering system for our Lobo II processing facility. In the second quarter of 2017, we completed the construction of an expansion of the Lobo II processing facility, which provided an additional 60 MMcf/d of processing capacity to the existing 95 MMcf/d provided by the Lobo processing facilities. Furthermore, we are constructing an additional expansion of the Lobo II processing facility, which will increase capacity by 15 MMcf/d and is expected to be completed during the first half of 2018. In 2018, we will also expand our gas processing capacity at our Lobo facilities by 200 MMcf/d through the construction of the Lobo III cryogenic gas processing plant, which is expected to be operational around the second half of 2018.

Greater Chickadee Crude Oil Gathering System. In March 2017, we completed construction and began operations of a crude oil gathering system in Upton and Midland counties, Texas in the Permian Basin, which we refer to as "Greater Chickadee." Greater Chickadee includes over 185 miles of high- and low-pressure pipelines that transport crude oil volumes to several major market outlets and other key hub centers in the Midland, Texas area and is supported by long-term contracts. Greater Chickadee also includes multiple central tank batteries, together with pump, truck injection and storage stations to maximize shipping and delivery options for our producer customers.

Marathon Petroleum Joint Venture. In April 2017, we completed construction and began operating a new NGL pipeline, which is part of our 50/50 joint venture with a subsidiary of Marathon Petroleum Company ("Marathon Petroleum"). This joint venture, Ascension Pipeline Company, LLC (the "Ascension JV"), is a bolt-on project to our Cajun-Sibon NGL system and is supported by long-term, fee-based contracts with Marathon Petroleum.

Sale of Non-Core Assets

In March 2017, we completed the sale of our ownership interest in HEP for net proceeds of $189.7 million. For the year ended December 31, 2016, we recorded an impairment loss of $20.1 million to reduce the carrying value of our investment to the expected sales price. Upon the sale of HEP in March 2017, we recorded an additional loss of $3.4 million for the year ended December 31, 2017 based on the adjusted sales price at closing.

Acquisitions, Organic Growth and Asset Sales in 2015 and 2016

- In January 2015, we acquired 100% of the voting equity interests of LPC Crude Oil Marketing LLC ("LPC"), which has crude oil gathering, transportation and marketing operations in the Permian Basin, for approximately $108.1 million.

- In March 2015, we acquired 100% of the voting equity interests in Coronado Midstream Holdings LLC ("Coronado"), which owns natural gas gathering and processing facilities in the Permian Basin, for approximately $600.3 million.

- In April 2015, we acquired VEX, located in the Eagle Ford Shale in South Texas, together with 100% of the voting equity interests (the "VEX interests") in certain entities, from Devon in a drop down transaction (the "VEX Drop Down") for $166.7 million in cash and approximately $9.0 million in common units. Additionally, we assumed $40.0 million in construction costs related to VEX.

- In October 2015, we acquired 100% of the voting equity interests in a subsidiary of Matador Resources Company ("Matador"), which has gathering and processing operations in the Delaware Basin, for approximately $141.3 million.

- Prior to November 2015, we co-owned the Deadwood natural gas processing plant with a subsidiary of Apache Corporation ("Apache"). In November 2015, we acquired Apache's 50% ownership interest in the Deadwood natural gas processing facility for approximately $40.1 million. We now own 100% of the Deadwood processing plant.

- In 2015, we completed the EMH Drop Downs.

- In January 2016, ENLK and ENLC acquired an 83.9% and 16.1% interest, respectively, in EnLink Oklahoma T.O. for aggregate consideration of approximately $1.4 billion. The EnLink Oklahoma T.O. assets serve gathering and processing needs in the growing STACK and CNOW plays in Central Oklahoma and are supported by long-term, fixed-fee contracts with acreage dedications that, at the time of acquisition, had a weighted-average term of approximately 15 years.

- In April 2016, we completed construction of the 100 MMcf/d Riptide processing plant in the Permian Basin.

- In August 2016, we formed the Delaware Basin JV with NGP to operate and expand our natural gas, natural gas liquids and crude oil midstream assets in the Delaware Basin. The Delaware Basin JV is owned 50.1% by us and 49.9% by NGP.

- In October 2016, we completed construction of the initial phase of the 60 MMcf/d Lobo II processing facilities.

- In November 2016, we formed the Cedar Cove JV with Kinder Morgan, Inc., which consists of gathering and compression assets in Blaine County, Oklahoma, located in the heart of the STACK play. The gathering system has a capacity of 25 MMcf/d with over 50,000 gross acres of dedications and ties into our existing Oklahoma assets. All gas gathered by the Cedar Cove JV is processed at our Central Oklahoma processing system. We hold a 30% ownership interest of the Cedar Cove JV, and Kinder Morgan, Inc. holds the remaining 70% ownership interest.

- In December 2016, we sold the North Texas Pipeline (the “NTPL”), a 140-mile natural gas transportation pipeline, for $84.6 million. We maintain capacity on the NTPL at competitive rates and at levels sufficient to support current and expected operations. As a result of the sale, we recorded a loss of $13.4 million for the year ended December 31, 2016.

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Our Assets

Our assets consist of gathering systems, transmission pipelines, processing facilities, fractionation facilities, stabilization facilities, storage facilities and ancillary assets. Except as stated otherwise, the following tables provide information about our assets as of and for the year ended December 31, 2017:

Gathering and Transmission Pipelines	Approximate Length (Miles)	Compression (HP) (1)	Estimated Capacity (2)	Year Ended December 31, 2017 Average Throughput (3)
Gas Pipelines				
Texas assets:				
Bridgeport rich and lean gathering systems	2,840	204,000	861	811,000
Johnson County gathering system	290	44,000	589	134,300
Silver Creek gathering system	720	77,000	522	390,600
Acacia transmission system	130	16,600	920	565,700
North Texas assets	3,980	341,600	2,892	1,901,600
MEGA System gathering facilities	700	105,300	393	262,500
Lobo gathering system (4)	125	15,200	82	98,800
Permian Basin assets (4)	825	120,500	475	361,300
Texas assets	4,805	462,100	3,367	2,262,900
Oklahoma assets:				
Central Oklahoma gathering system	1,500	203,500	937	789,000
Northridge gathering system	140	14,000	65	40,300
Oklahoma assets	1,640	217,500	1,002	829,300
Louisiana assets:				
Louisiana gas gathering and transmission system	3,215	97,400	3,975	1,995,800
Total Gas Pipelines	9,660	777,000	8,344	5,088,000
NGL, Crude Oil and Condensate Pipelines				
Louisiana assets:				
Cajun-Sibon pipeline system	770	—	130,000	119,200
Ascension pipeline (5)	20	—	50,000	13,500
Louisiana assets	790	—	180,000	132,700
Crude and condensate assets:				
Ohio River Valley (6)	210	—	25,650	20,600
Victoria Express Pipeline	60	—	90,000	15,100
Permian gathering (7)	360	—	118,500	76,700
Total NGL, Crude Oil and Condensate Pipelines	1,420	—	414,150	245,100

(1) Includes power generation units.
(2) Estimated capacity for gas pipelines is MMcf/d. A volume capacity of 100 MMcf/d correlates to an approximate energy content of 100,000 MMBtu/d. Estimated capacity for liquids and crude and condensate pipelines is Bbls/d.
(3) Average throughput for gas pipelines is MMBtu/d. Average throughput for NGL, crude and condensate pipelines is Bbls/d.
(4) Includes gross mileage, compression, capacity and throughput for the Delaware Basin JV, which is owned 50.1% by us. Estimated capacity on our Lobo gathering system includes only the Delaware Basin JV's compression capacity and does not include gas compressed by third parties on our system.
(5) Includes gross mileage, capacity and throughput for the Ascension JV, which is owned 50% by us.
(6) Estimated capacity is comprised of trucking capacity only.
(7) Estimated capacity is comprised of 68,500 Bbls/d of pipeline capacity and 50,000 Bbls/d of trucking capacity.

Processing Facilities	Processing Capacity (MMcf/d)	Year Ended December 31, 2017 Average Throughput (MMBtu/d)
Texas assets:		
Bridgeport processing facility	800	605,500
Silver Creek processing system	280	193,600
North Texas assets	1,080	799,100
MEGA system processing facilities	408	291,100
Lobo processing facilities	155	94,200
Permian Basin assets	563	385,300
Texas assets	1,643	1,184,400
Oklahoma Assets:		
Central Oklahoma processing facilities	1,005	759,500
Northridge processing facility	200	50,800
Oklahoma assets	1,205	810,300
Louisiana assets:		
Louisiana gas processing facilities	1,903	453,300
Total Processing Facilities	4,751	2,448,000

Fractionation Facilities	Estimated NGL Fractionation Capacity (MBbls/d)	Year Ended December 31, 2017 Average Throughput (Bbls/d)
Louisiana assets:		
Plaquemine fractionation facility (1)	110	59.9
Plaquemine processing plant	11	4.0
Eunice fractionation facility	55	43.1
Riverside fractionation facility (1)	—	30.4
Louisiana assets	176	137.4
Texas assets:		
Bridgeport processing facility (2)	15	—
Mesquite terminal (2)	15	—
Texas assets	30	—
Gulf Coast Fractionators (3)	56	38.9
Total Fractionation Facilities	262	176.3

(1) The Plaquemine fractionation facility produces purity ethane and propane for sale to markets via pipeline, while butane and heavier products are sent to the Riverside fractionation facility for further processing. The Plaquemine fractionation facility and the Riverside fractionation facility have an aggregate fractionation capacity of 110 MBbls/d.

(2) We have two fractionation facilities with capacity of 15 MBbls/d each. Our Mesquite terminal in the Permian Basin and our Bridgeport processing plant in North Texas provide operational flexibility for the related processing plants but are not the primary fractionation facilities for the NGLs produced by the processing plants. Under our current contracts, we do not earn fractionation fees for operating these facilities, so throughput volumes through these facilities are not captured on a routine basis and are not significant to our gross operating margins.

(3) Volumes shown reflect only our contractual right to the benefits and burdens of a 38.75% economic interest in Gulf Coast Fractionators held by Devon.

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Storage Assets	Estimated Storage Capacity (1)
Gas storage:	
Belle Rose gas storage facility	11.9
Sorrento gas storage facility	7.3
Total gas storage	19.2
NGL storage:	
Napoleonville NGL storage facility	4.7
Crude oil storage:	
ORV storage	0.5
VEX storage	0.2
Total crude oil storage	0.7

(1) Estimated capacity for gas storage is Bcf, and includes linefill capacity necessary to operate storage facilities. Estimated capacity for NGL and crude oil storage is MMBbls.

Texas Assets. Our Texas assets include transmission pipelines, processing facilities and gathering systems in the Barnett Shale in North Texas and the Permian Basin in West Texas.

- Acacia Transmission System. The Acacia transmission system is a pipeline that connects production from the Barnett Shale to markets in North Texas accessed by Atmos Energy, Brazos Electric, Enbridge Energy Partners, Energy Transfer Partners, Enterprise Product Partners and GDF Suez. Devon is the Acacia transmission system's only customer with approximately six years remaining on a fixed-fee transportation agreement that covers transmission services and includes annual rate escalators.

- Processing and Fractionation Facilities. Our processing facilities in Texas include 10 gas processing plants and consist of the following:

    - *North Texas Assets.* Our North Texas processing systems include the following:

        - *Bridgeport processing facility.* Our Bridgeport natural gas processing facility, located in Wise County, Texas, approximately 40 miles northwest of Fort Worth, Texas, is one of the largest processing plants in the U.S. with seven cryogenic turboexpander plants. Devon is the Bridgeport facility's largest customer, providing substantially all of the natural gas processed for the year ended December 31, 2017. We currently have approximately six years remaining on a fixed-fee processing agreement with Devon pursuant to which we provide processing services for natural gas delivered by Devon to the Bridgeport processing facility. This contractual arrangement includes an MVC from Devon of 650 MMcf/d of natural gas delivered to the Bridgeport processing facility that will remain in effect up to January 1, 2019.

        - *Silver Creek processing system.* Our Silver Creek processing system, located in Weatherford, Azle and Fort Worth, Texas, includes three processing plants: the Azle plant, the Silver Creek plant and the Goforth plant, which account for 50 MMcf/d, 200 MMcf/d and 30 MMcf/d of processing capacity, respectively.

    - *Permian Basin Assets*. Our Permian Basin processing facilities consist of the following:

        - *MEGA system processing facilities.* Our Permian Basin processing plants are located in Midland, Martin, and Glasscock counties, Texas and operate as a connected system. These assets consist of the Bearkat processing facility with a capacity of 75 MMcf/d, the Deadwood processing facility with a capacity of 58 MMcf/d, the Midmar processing facilities with a capacity of 175 MMcf/d and the Riptide processing facility with a capacity of 100 MMcf/d (collectively, the "Midland Energy Gathering Area" or "MEGA system").

- *Lobo processing facilities*. Our Lobo natural gas processing facilities are located in Loving County, Texas and include two processing plants, the Lobo I plant and the Lobo II plant, which account for 35 MMcf/d and 120 MMcf/d of processing capacity, respectively. The Lobo processing facilities and the connected gathering system are owned by the Delaware Basin JV.

- Gathering Systems. Our gathering systems in Texas are connected to our North Texas or Permian Basin processing assets.

  - *North Texas Assets.* Our North Texas gathering systems include the following:

    - *Bridgeport rich gathering system.* A substantial majority of the natural gas gathered on the Bridgeport rich gas gathering system is delivered to the Bridgeport processing facility. Devon is the largest customer on the Bridgeport rich gathering system contributing substantially all of the natural gas gathered for the year ended December 31, 2017. As described above, we currently have approximately six years remaining on a fixed-fee gathering agreement with Devon pursuant to which we provide gathering services on the Bridgeport system. The agreement includes an MVC from Devon that will remain in effect up to January 1, 2019, with a combined 850 MMcf/d of natural gas to be delivered for gathering into the Bridgeport rich and Bridgeport lean gathering systems.

    - *Bridgeport lean gathering system.* Natural gas gathered on the Bridgeport lean gathering system is all attributable to Devon and is delivered to the Acacia transmission system and to intrastate pipelines without processing. As described above, we are party to a fixed-fee gathering and processing agreement with Devon that covers gathering services on the Bridgeport system.

    - *Johnson County gathering system*. Natural gas gathered on this system is primarily attributable to Devon and is delivered to intrastate pipelines without processing. We currently have approximately six years remaining on a fixed-fee gathering agreement pursuant to which we provide gathering services on the Johnson County gathering system. This contractual arrangement includes an MVC from Devon that will remain in effect up to January 1, 2019, with 125 MMcf/d of natural gas to be delivered for gathering into the Johnson County gathering system.

    - *Silver Creek gathering system*. Our Silver Creek gathering system is located primarily in Hood, Parker and Johnson counties, Texas, and connects to the Silver Creek processing system.

  - *Permian Basin assets*. Our Permian Basin gathering systems include the following:

    - *MEGA system gathering facilities*. This gathering system in the Permian Basin serves as an interconnected system of pipelines and compressors to deliver gas from wellheads in the Permian Basin to the MEGA system processing facilities.

    - *Lobo gathering system.* The rich natural gas gathering system consists of gathering pipeline and compression assets in the Delaware Basin primarily in Texas, with a minor portion in New Mexico. The Lobo gathering system is owned by the Delaware Basin JV.

Oklahoma Assets. Our Oklahoma assets consist of processing facilities and gathering systems in southern and Central Oklahoma.

- Oklahoma processing system. Our processing facilities include the following:

  - *Central Oklahoma processing facilities.* The Central Oklahoma plants include the Chisholm plants, the Battle Ridge plant and the Cana processing facilities (collectively, the "Central Oklahoma processing system"), which account for 520 MMcf/d, 85 MMcf/d and 400 MMcf/d of processing capacity, respectively. The residue natural gas from the Cana processing facility is delivered to Enable Midstream Partners and ONEOK. The unprocessed NGLs from the Chisholm facilities are transported by ONEOK to NGL transmission lines, which then transport the NGLs to our fractionators in Louisiana. Devon is the primary customer of the Cana processing facilities and has approximately six years remaining on a fixed-fee gathering and processing agreement with us pursuant to which we provide processing services for natural gas delivered by Devon to the Cana processing facility. In addition, contractual arrangements related to the Central Oklahoma processing system that contain an MVC include the following:

- Our contractual arrangement with Devon includes an MVC that will remain in effect until October 2020. For 2018, the MVC dictates that approximately 145 MMcf/d of natural gas will be delivered to the Chisholm plant processing facility. The MVC escalates quarterly, resulting in approximately 230 MMcf/d to be delivered in 2020.

- We have another contractual arrangement with Devon that includes an MVC that will remain in effect up to January 1, 2019 with 330 MMcf/d of natural gas to be delivered to the Cana processing facility.

- *Northridge processing facility.* Our Northridge processing plant is located in Hughes County in the Arkoma-Woodford Shale in southeastern Oklahoma. The residue natural gas from the Northridge processing facility is delivered to Centerpoint, Enable Midstream Partners and MPLX.

- Oklahoma gathering system. Our Oklahoma gathering systems include the following:

  - *Central Oklahoma gathering system.* The Central Oklahoma gathering system serves the STACK and CNOW plays. Contractual arrangements related to the Central Oklahoma gathering system that contain an MVC include the following:

    - Our contractual arrangement with Devon includes an MVC that will remain in effect until October 2020. For 2018, the MVC dictates that approximately 153 MMcf/d of natural gas will be handled through the Chisholm gathering system. The MVC escalates quarterly, resulting in approximately 230 MMcf/d to be delivered in 2020.

    - We have another contractual arrangement with Devon that includes an MVC that will remain in effect up to January 1, 2019, with 330 MMcf/d of natural gas to be handled through the Cana gathering system.

  - *Northridge gathering system.* Our Northridge gathering system is located in the Arkoma-Woodford Shale in Southeastern Oklahoma.

Louisiana Assets. Our Louisiana assets consist of gas and NGL transmission pipelines, processing facilities, gathering systems and gas and NGL storage.

- Louisiana Gas Pipeline and Processing Systems. The Louisiana gas pipeline system includes gathering and transmission systems, processing facilities and underground gas storage.

  - *Gas Transmission and Gathering Systems.* Our transmission system consists of a portfolio of large capacity interconnections with the Gulf Coast pipeline grid that provides customers with supply access to multiple domestic production basins for redelivery to major industrial market consumption located primarily in the Mississippi River Corridor between Baton Rouge and New Orleans. Our natural gas transmission services are supplemented by fully integrated, high deliverability salt dome storage capacity strategically located in the natural gas consumption corridor. In combination with our transmission system, our gathering systems provide a fully integrated wellhead to burner tip value chain that includes local gathering, processing and treating services to Louisiana producers.

  - *Gas Processing and Storage Facilities.* Our processing facilities in Louisiana include five gas processing plants, of which three are currently operational.

    - *Plaquemine Processing Plant.* The Plaquemine processing plant has 225 MMcf/d of processing capacity and is connected to the Plaquemine fractionation facility.

    - *Gibson Processing Plant.* The Gibson processing plant has 110 MMcf/d of processing capacity and is located in Gibson, Louisiana. The processing plant is connected to our Louisiana gathering system.

    - *Pelican Processing Plant*. The Pelican processing plant complex is located in Patterson, Louisiana and has a designed capacity of 600 MMcf/d of natural gas. The Pelican processing plant is connected with continental shelf and deepwater production and has downstream connections to the ANR Pipeline. This plant has an interconnection with the Louisiana gas pipeline system allowing us to process natural gas from this system at our Pelican processing plant when markets are favorable.

    - *Blue Water Gas Processing Plant*. We operate and own a 64.29% interest in the Blue Water gas processing plant. The Blue Water gas processing plant is located in Crowley, Louisiana and is connected to the Blue Water pipeline system. Our share of the plant’s capacity is approximately 193 MMcf/d. The plant is not expected to operate in the future unless fractionation spreads are favorable and volumes are sufficient to run the plant.

    - *Eunice Processing Plant*. The Eunice processing plant is located in south central Louisiana and has a capacity of 475 MMcf/d of natural gas. In August 2013, we shut down the Eunice processing plant due to adverse economics driven by low NGL prices and low processing volumes, which we do not see improving in the near term based on forecasted prices.

    - *Sabine Pass Processing Plant*. The Sabine Pass processing plant is located east of the Sabine River at Johnson's Bayou, Louisiana and has a processing capacity of 300 MMcf/d of natural gas. In 2013, we shut down the Sabine Pass processing plant and do not anticipate reopening the plant based on current market conditions.

  - *Belle Rose Gas Storage Facility*. The Belle Rose storage facility is located in Assumption Parish, Louisiana. This facility was placed in service in May 2016 and is designed for injecting pipeline quality gas into storage or withdrawing stored gas for delivery by pipeline.

  - *Sorrento Gas Storage Facility*. The storage facility is located in Assumption Parish, Louisiana. This facility is designed for injecting pipeline quality gas into storage or withdrawing stored gas for delivery by pipeline.

- Louisiana Liquids Pipeline System. Our Louisiana liquids pipeline system includes NGL transport lines, fractionation assets and underground NGL storage.

  - *Cajun-Sibon Pipeline System*. The Cajun-Sibon pipeline system transports unfractionated NGLs from areas such as the Liberty, Texas interconnects near Mont Belvieu and from our Gibson and Pelican processing plants in South Louisiana to either the Riverside or Eunice fractionators or to third-party fractionators when necessary.

  - *Ascension Pipeline*. The Ascension JV is an NGL pipeline that connects our Riverside fractionator to Marathon Petroleum’s Garyville refinery and is owned 50% by Marathon Petroleum.

  - *Fractionation Facilities*. There are four fractionation facilities located in Louisiana that are connected to our processing facilities, and to Mont Belvieu and other hubs through our Cajun-Sibon pipeline system.

    - *Plaquemine Fractionation Facility*. The Plaquemine fractionator is located at our Plaquemine gas processing plant complex and is connected to our Cajun-Sibon pipeline. The Plaquemine fractionation facility produces purity ethane and propane for sale to markets via pipeline, while butane and heavier products are sent to our Riverside facility for further processing. The Plaquemine fractionator, collectively with the Riverside Fractionation Facility, has an approximate capacity of 110,000 Bbls/d of raw-make NGL products.

    - *Plaquemine Gas Processing Plant*. In addition to the Plaquemine fractionation facility, the adjacent Plaquemine Gas Processing Plant also has an on-site fractionator.

    - *Eunice Fractionation Facility*. The Eunice fractionation facility is located in south central Louisiana. Liquids are delivered to the Eunice fractionation facility by the Cajun-Sibon pipeline. The Eunice fractionation facility is directly connected to the southeast propane market and to a third-party storage facility.

- *Riverside Fractionation Facility.* The Riverside fractionator and loading facility is located on the Mississippi River upriver from Geismar, Louisiana. Liquids are delivered to the Riverside fractionator by the Cajun-Sibon pipeline system from the Eunice and Pelican processing plants or by third-party truck and rail assets. The loading/unloading facility has the capacity to transload 15,000 Bbls/d of crude oil and condensate from rail cars to barges.

- *Napoleonville Storage Facility.* The Napoleonville NGL storage facility is connected to the Riverside facility and is comprised of two existing caverns. The caverns are currently operated in butane service, and space is leased to customers for a fee.

Crude and Condensate. Our Crude and Condensate assets consist of crude oil and condensate pipelines, above ground storage and a trucking fleet.

- *Ohio River Valley.* Our ORV operations are an integrated network of assets comprised of a 5,000-barrel-per-hour crude oil and condensate barge loading terminal on the Ohio River, a 20-spot crude oil and condensate rail loading terminal on the Ohio Central Railroad network, crude oil and condensate pipelines in Ohio and West Virginia, above ground crude oil storage, a trucking fleet comprised of both semi and straight trucks, trailers for hauling NGL volumes and seven existing brine disposal wells. Additionally, our ORV operations include eight condensate stabilization and natural gas compression stations that are supported by long-term, fee-based contracts with multiple producers.

- *Permian Crude and Condensate.* Our Permian Crude and Condensate assets have crude oil gathering, transportation and marketing operations in the Permian Basin. These assets include trucking and crude gathering pipelines acquired in the LPC acquisition and the Greater Chickadee gathering system, which was placed into service in March 2017 and delivers crude oil for customers to Enterprise Product Partners L.P.'s crude oil terminal in West Texas. Greater Chickadee also includes multiple central tank batteries, with pump, truck injection and storage stations to maximize shipping and delivery options for producers.

- *Black Coyote Crude Oil Gathering System.* We are expanding our operations in the core of the STACK play in Central Oklahoma with the construction of the Black Coyote crude oil gathering system. Black Coyote is primarily being built on dedicated acreage from Devon, which will be the main shipper on the system. The system is expected to be operational in the first quarter of 2018.

- *Victoria Express Pipeline.* VEX includes a multi-grade crude oil pipeline with terminals in Cuero and the Port of Victoria Terminal and barge docks. The Cuero truck unloading terminal at the origin of the VEX system contains eight unloading bays and above-ground storage capacity for receipt from and delivery to the VEX pipeline. The VEX pipeline terminates at the Port of Victoria Terminal, which has an eight-bay truck unloading dock and above-ground storage capacity. The Port of Victoria Terminal delivers to two barge loading docks at the Port of Victoria. We have an agreement with Devon, which includes an MVC of 30,000 Bbls/d, that will remain in effect until July 2019.

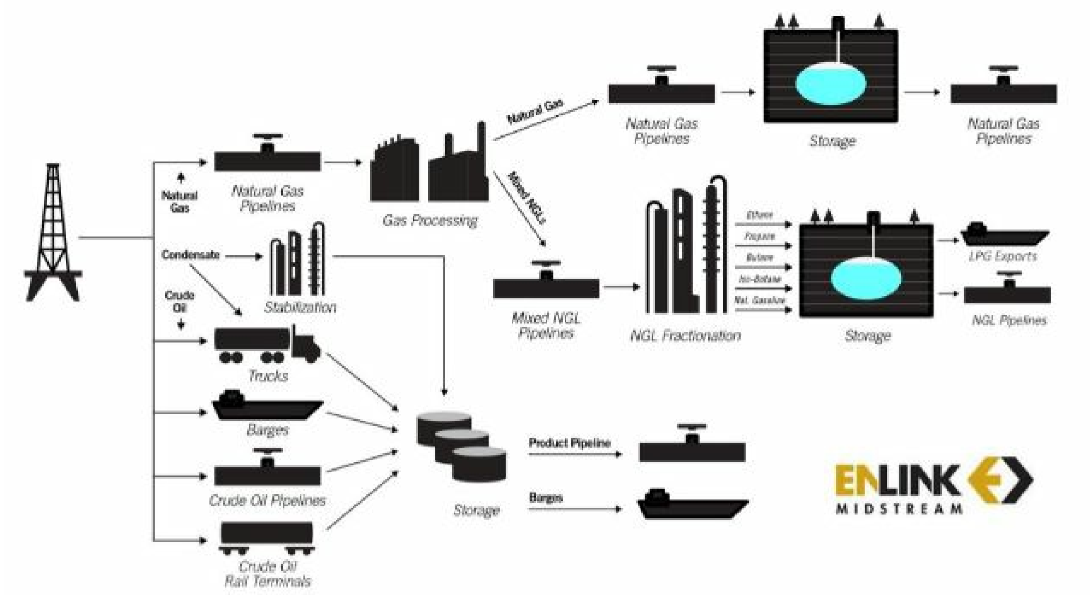
Corporate. Our Corporate assets primarily consist of a contractual right to the benefits and burdens associated with Devon's 38.75% ownership interest in GCF and a 30% ownership interest in the Cedar Cove JV.

- *Gulf Coast Fractionators.* We are entitled to receive the economic benefits and burdens of the 38.75% interest in GCF held by Devon, with the remaining interests owned 22.5% by Phillips 66 and 38.75% by Targa Resources Partners. GCF owns an NGL fractionator located on the Gulf Coast at Mont Belvieu, Texas. Phillips 66 is the operator of the fractionator. GCF receives raw mix NGLs from customers, fractionates the raw mix and redelivers the finished products to the customers for a fee.

- *Cedar Cove JV.* On November 9, 2016, we formed a joint venture with Kinder Morgan, Inc. consisting of gathering and compression assets in Blaine County, Oklahoma, which tie into our existing Oklahoma assets. All gas gathered by the Cedar Cove JV is processed by our Central Oklahoma processing facilities. We own 30% of the Cedar Cove JV.

Industry Overview

The following diagram illustrates the gathering, processing, fractionation, stabilization and transmission process.



The midstream industry is the link between the exploration and production of natural gas and crude oil and condensate and the delivery of its components to end-user markets. The midstream industry is generally characterized by regional competition based on the proximity of gathering systems and processing plants to natural gas and crude oil and condensate producing wells.

Natural gas gathering. The natural gas gathering process follows the drilling of wells into gas-bearing rock formations. After a well has been completed, it is connected to a gathering system. Gathering systems typically consist of a network of small diameter pipelines and, if necessary, compression and treating systems that collect natural gas from points near producing wells and transport it to larger pipelines for further transmission.

Compression. Gathering systems are operated at pressures that will maximize the total natural gas throughput from all connected wells. Because wells produce gas at progressively lower field pressures as they age, it becomes increasingly difficult to deliver the remaining production in the ground against the higher pressure that exists in the connected gathering system. Natural gas compression is a mechanical process in which a volume of gas at an existing pressure is compressed to a desired higher pressure, allowing gas that no longer naturally flows into a higher-pressure downstream pipeline to be brought to market. Field compression is typically used to allow a gathering system to operate at a lower pressure or provide sufficient discharge pressure to deliver gas into a higher-pressure downstream pipeline. The remaining natural gas in the ground will not be produced if field compression is not installed because the gas will be unable to overcome the higher gathering system pressure. A declining well can continue delivering natural gas if field compression is installed.

Natural gas processing. The principal components of natural gas are methane and ethane, but most natural gas also contains varying amounts of heavier NGLs and contaminants, such as water and CO_2, sulfur compounds, nitrogen or helium. Natural gas produced by a well may not be suitable for long-haul pipeline transportation or commercial use and may need to be processed to remove the heavier hydrocarbon components and contaminants. Natural gas in commercial distribution systems mostly consists of methane and ethane, and moisture and other contaminants have been removed so there are negligible amounts of them in the gas stream. Natural gas is processed to remove unwanted contaminants that would interfere with pipeline transportation or use of the natural gas and to separate those hydrocarbon liquids from the gas that have higher value as NGLs. The removal and separation of individual hydrocarbons through processing is possible due to differences in weight, boiling point, vapor pressure and other physical characteristics. Natural gas processing involves the separation of natural gas into pipeline-quality natural gas and a mixed NGL stream and the removal of contaminants.

NGL fractionation. NGLs are separated into individual, more valuable components during the fractionation process. NGL fractionation facilities separate mixed NGL streams into discrete NGL products: ethane, propane, isobutane, normal butane, natural gasoline and stabilized crude oil and condensate. Ethane is primarily used in the petrochemical industry as feedstock for ethylene, one of the basic building blocks for a wide range of plastics and other chemical products. Propane is used as a petrochemical feedstock in the production of ethylene and propylene and as a heating fuel, an engine fuel and industrial fuel. Isobutane is used principally to enhance the octane content of motor gasoline. Normal butane is used as a petrochemical feedstock in the production of ethylene and butylene (a key ingredient in synthetic rubber), as a blend stock for motor gasoline and to derive isobutene through isomerization. Natural gasoline, a mixture of pentanes and heavier hydrocarbons, is used primarily as motor gasoline blend stock or petrochemical feedstock.

Natural gas transmission. Natural gas transmission pipelines receive natural gas from mainline transmission pipelines, processing plants and gathering systems and deliver it to industrial end-users, utilities and to other pipelines.

Crude oil and condensate transmission. Crude oil and condensate are transported by pipelines, barges, rail cars and tank trucks. The method of transportation used depends on, among other things, the resources of the transporter, the locations of the production points and the delivery points, cost-efficiency and the quantity of product being transported.

Condensate Stabilization. Condensate stabilization is the distillation of the condensate product to remove the lighter end components, which ultimately creates a higher quality condensate product that is then delivered via truck, rail or pipeline to local markets.

Brine gathering and disposal services. Typically, shale wells produce significant amounts of water that, in most cases, require disposal. Produced water and frac-flowback is hauled via truck transport or is pumped through pipelines from its origin at the oilfield tank battery or drilling pad to the disposal location. Once the water reaches the delivery disposal location, water is processed and filtered to remove impurities and injection wells place fluids underground for storage and disposal.

Storage. Demand for natural gas, NGLs and crude oil fluctuate daily and seasonally, while production and pipeline deliveries are relatively constant in the short term. Storage of products during periods of low demand helps to ensure that sufficient supplies are available during periods of high demand. Natural gas and NGLs are stored in large volumes in underground facilities and in smaller volumes in tanks above and below ground, while crude oil is typically stored in tanks above ground.

Crude oil and condensate terminals. Crude oil and condensate rail terminals are an integral part of ensuring the movement of new crude oil and condensate production from the developing shale plays in the United States and Canada. In general, the crude oil and condensate rail loading terminals are used to load rail cars and transport the commodity out of developing basins into market rich areas of the country where crude oil and condensate rail unloading terminals are used to unload rail cars and store crude oil and condensate volumes for third parties until the crude oil and condensate is redelivered to premium market delivery points via pipelines, trucks or rail.

Balancing Supply and Demand

When we purchase natural gas, crude oil and condensate, we establish a margin normally by selling it for physical delivery to third-party users. We can also use over-the-counter derivative instruments or enter into future delivery obligations under futures contracts on the New York Mercantile Exchange (“NYMEX”) related to our natural gas purchases. Through these transactions, we seek to maintain a position that is balanced between (1) purchases and (2) sales or future delivery obligations. Our policy is not to acquire and hold natural gas futures contracts or derivative products for the purpose of speculating on price changes.

Competition

The business of providing gathering, transmission, processing and marketing services for natural gas, NGLs, crude oil and condensate is highly competitive. We face strong competition in obtaining natural gas, NGLs, crude oil and condensate supplies and in the marketing and transportation of natural gas, NGLs, crude oil and condensate. Our competitors include major integrated and independent exploration and production companies, natural gas producers, interstate and intrastate pipelines, other natural gas, NGLs and crude oil and condensate gatherers and natural gas processors. Competition for natural gas and crude oil and condensate supplies is primarily based on geographic location of facilities in relation to production or markets, the reputation, efficiency and reliability of the gatherer and the pricing arrangements offered by the gatherer. For areas where acreage is not dedicated to us, we will compete with similar enterprises in providing additional gathering and processing services in its respective areas of operation, which may offer more services or have strong financial resources and access to larger natural gas, NGLs, crude oil and condensate supplies than we do. Our competition varies in different geographic areas.

In marketing natural gas, NGLs, crude oil and condensate, we have numerous competitors, including marketing affiliates of interstate pipelines, major integrated oil and gas companies, and local and national natural gas producers, gatherers, brokers and marketers of widely varying sizes, financial resources and experience. Local utilities and distributors of natural gas are, in some cases, engaged directly and through affiliates in marketing activities that compete with our marketing operations.

We face strong competition for acquisitions and development of new projects from both established and start-up companies. Competition increases the cost to acquire existing facilities or businesses and results in fewer commitments and lower returns for new pipelines or other development projects. Our competitors may have greater financial resources than we possess or may be willing to accept lower returns or greater risks. Our competition differs by region and by the nature of the business or the project involved.

Natural Gas, NGL, Crude Oil and Condensate Supply

Our gathering and transmission pipelines have connections with major intrastate and interstate pipelines, which we believe have ample natural gas and NGL supplies in excess of the volumes required for the operation of these systems. We evaluate well and reservoir data that is either publicly available or furnished by producers or other service providers in connection with the construction and acquisition of our gathering systems and assets to determine the availability of natural gas, NGLs, crude oil and condensate supply for our systems and assets and/or obtain an MVC from the producer that results in a rate of return on investment. We do not routinely obtain independent evaluations of reserves dedicated to our systems and assets due to the cost and relatively limited benefit of such evaluations. Accordingly, we do not have estimates of total reserves dedicated to our systems and assets or the anticipated life of such producing reserves.

Credit Risk and Significant Customers

We are subject to risk of loss resulting from nonpayment or nonperformance by our customers and other counterparties, such as our lenders and hedging counterparties. We diligently attempt to ensure that we issue credit to only credit-worthy customers. However, our purchase and resale of crude oil, condensate, NGLs and natural gas exposes us to significant credit risk, as the margin on any sale is generally a very small percentage of the total sales price. Therefore, a credit loss can be very large relative to our overall profitability. A substantial portion of our throughput volumes come from customers that have investment-grade ratings. However, lower commodity prices in future periods may result in a reduction in our customers' liquidity and ability to make payments or perform on their obligations to us. Some of our customers have filed for bankruptcy protection, and their debts and payments to us are subject to laws governing bankruptcy.

For the years ended December 31, 2017, 2016 and 2015, Devon represented 14.4%, 18.5% and 16.6%, respectively, of our consolidated revenues, and Dow Hydrocarbons & Resources LLC ("Dow Hydrocarbons") represented 11.2%, 10.8% and 11.7%, respectively, of our consolidated revenues. No other customer represented greater than 10.0% of our revenue. Our operations are dependent on the volume of natural gas that Devon provides to us under commercial agreements, which constitutes a substantial portion of our natural gas supply. The loss of Devon or Dow Hydrocarbons as a customer could have a material impact on our results of operations if we were not able to sell our products to another customer with similar margins because the gross operating margins received from transactions with Devon and Dow Hydrocarbons are material to our total gross operating margin.

Regulation

Natural Gas Pipeline Regulation. We own interstate natural gas pipelines that are subject to regulation as natural gas companies by the Federal Energy Regulatory Commission ("FERC") under the Natural Gas Act ("NGA"). FERC regulates the rates and terms and conditions of service on interstate natural gas pipelines, as well as the certification, construction, modification, expansion and abandonment of facilities.

The rates and terms and conditions for our interstate pipeline services must be just and reasonable and not unduly preferential or unduly discriminatory, although negotiated or settlement rates may be accepted in certain circumstances. Such rates and terms and conditions are set forth in FERC-approved tariffs. Proposed rate increases and changes to our tariffs are subject to FERC approval. Pursuant to FERC's jurisdiction over rates, existing rates may be challenged by complaint or by FERC on its own initiative, and proposed new or changed rates may be challenged by protest. If protested, a rate increase may be suspended for up to five months and collected, subject to refund. If, upon completion of an investigation, FERC finds that the new or changed rate is unlawful, it is authorized to require the pipeline to refund revenues collected in excess of the just and reasonable rate during the term of the investigation.

The rates charged by our FERC regulated natural gas pipelines may also be affected by the ongoing uncertainty regarding FERC's current income tax allowance policy. In July 2016, the United States Court of Appeals for the District of Columbia Circuit issued its opinion in *United Airlines, Inc., et al.v. FERC*, finding that FERC had acted arbitrarily and capriciously when it failed to demonstrate that permitting an interstate petroleum products pipeline organized as a limited partnership to include an income tax allowance in the cost of service underlying its rates in addition to the discounted cash flow return on equity would not result in the pipeline double-recovering its investors' income taxes. The court vacated FERC's order and remanded to FERC to consider mechanisms for demonstrating that there is no double recovery as a result of the income tax allowance. On December 15, 2016, FERC issued a Notice of Inquiry seeking comment on how to address any double recovery resulting from its income tax allowance policy. FERC is currently considering whether, and if so, to what extent, pipelines owned by pass-through entities such as MLPs may include income tax allowance in rates to compensate for the income tax liability of investors.

Interstate natural gas pipelines regulated by FERC are required to comply with numerous regulations related to standards of conduct, market transparency, and market manipulation. FERC's standards of conduct regulate the manner in which interstate natural gas pipelines may interact with their marketing affiliates. FERC's market oversight and transparency regulations require regulated entities to submit annual reports of threshold purchases or sales of natural gas and publicly post certain information on scheduled volumes. FERC's market manipulation regulations, promulgated pursuant to the Energy Policy Act of 2005 (the "EPAct 2005"), 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) make any untrue statement of material fact or omit to state a material fact necessary to make the statements made not misleading (in light of the circumstances under which the statements were made); or (3) engage in any act, practice or course of business that operates (or would operate) as a fraud or deceit upon any person. The EPAct 2005 also amends the NGA and the Natural Gas Policy Act of 1978 ("NGPA") to give FERC authority to impose civil penalties for violations of these statutes up to $1.0 million per day per violation for violations occurring after August 8, 2005. The maximum penalty authority established by the statute has been adjusted to $1.2 million per day per violation and will continue to be adjusted periodically for inflation. Should we fail to comply with all applicable FERC-administered statutes, rules, regulations and orders, we could be subject to substantial penalties and fines.

Certain of our intrastate natural gas pipelines also transport gas in interstate commerce and, thus, the rates, terms and conditions of such services are subject to FERC jurisdiction under Section 311 of the NGPA ("Section 311"). Pipelines providing transportation service under Section 311 are required to provide services on an open and nondiscriminatory basis, and the maximum rates for interstate transportation services provided by such pipelines must be "fair and equitable." Such rates are generally subject to review every five years by FERC or by an appropriate state agency.

In addition to Section 311 regulation, our intrastate natural gas pipeline operations are subject to regulation by various state agencies. Most state agencies possess the authority to review and authorize natural gas transportation transactions and the construction, acquisition, abandonment and interconnection of physical facilities for intrastate pipelines. State agencies also may regulate transportation rates, service terms and conditions and contract pricing.

Liquids Pipeline Regulation. We own certain liquids and crude oil pipelines that are regulated by FERC as common carrier interstate pipelines under the Interstate Commerce Act ("ICA"), the Energy Policy Act of 1992 and related rules and orders.

FERC regulation requires that interstate liquids pipeline rates and terms and conditions of service, including rates for transportation of crude oil, condensate and NGLs, be filed with FERC and that these rates and terms and conditions of service be "just and reasonable" and not unduly discriminatory or unduly preferential.

Rates of interstate liquids pipelines are currently regulated by FERC primarily through an annual indexing methodology, under which pipelines increase or decrease their rates in accordance with an index adjustment specified by FERC. This adjustment is subject to review every five years. For the five-year period beginning on July 1, 2016, FERC established an annual index adjustment equal to the change in the producer price index for finished goods plus 1.23%. On October 20, 2016, however, FERC issued an Advance Notice of Proposed Rulemaking indicating that FERC is considering a new policy that would deny proposed index increases for pipelines under certain circumstances where revenues exceed cost-of-service by a certain percentage or where the proposed index increases exceed certain annual cost changes reported to FERC. Under current FERC regulations, liquids pipelines can request a rate increase that exceeds the rate obtained through application of the indexing methodology by using a cost-of-service approach, but only after the pipeline establishes that a substantial divergence exists between the actual costs experienced by the pipeline and the rates resulting from application of the indexing methodology. The rates charged by our interstate liquids pipelines may also be affected by the ongoing uncertainty regarding FERC's current income tax allowance policy discussed above.

The ICA permits interested persons to challenge proposed new or changed rates and authorizes FERC to suspend the effectiveness of such rates for up to seven months and investigate such rates. If, upon completion of an investigation, FERC finds that the new or changed rate is unlawful, it is authorized to require the pipeline to refund revenues collected in excess of the just and reasonable rate during the term of the investigation. FERC may also investigate, upon complaint or on its own motion, rates that are already in effect and may order a carrier to change its rates prospectively. Under certain circumstances, FERC could limit our ability to set rates based on our costs or could order us to reduce our rates and pay reparations to complaining shippers for up to two years prior to the date of the complaint. FERC also has the authority to change our terms and conditions of service if it determines that they are unjust and unreasonable or unduly discriminatory or preferential.

As we acquire, construct and operate new liquids assets and expand our liquids transportation business, the classification and regulation of our liquids transportation services, including services that our marketing companies provide on our FERC-regulated liquids pipelines, are subject to ongoing assessment and change based on the services we provide and determinations by FERC and the courts. Such changes may subject additional services we provide to regulation by FERC.

Intrastate NGL and other petroleum pipelines are not generally subject to rate regulation by FERC, but they are subject to regulation by various agencies in the respective states where they are located. While such regulatory regimes vary, state agencies typically require intrastate NGL and petroleum pipelines to file their rates with the agencies and permit shippers to challenge existing rates or proposed rate increases.

Gathering Pipeline Regulation. Section 1(b) of the NGA exempts natural gas gathering facilities from the jurisdiction of FERC under the NGA. We own a number of natural gas pipelines that we believe meet the traditional tests FERC has used to establish that a pipeline is a gathering pipeline and therefore not subject to FERC jurisdiction. The distinction between FERC-regulated transmission services and federally unregulated gathering services is the subject of substantial, ongoing litigation, however, so the classification and regulation of our gathering facilities are subject to change. Application of FERC jurisdiction to our gathering facilities could increase our operating costs, decrease our rates and adversely affect our business. State regulation of gathering facilities generally includes various safety, environmental and, in some circumstances, nondiscriminatory requirements and complaint-based rate regulation.

In addition, we are subject to some state ratable take and common purchaser statutes. 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.

Natural Gas Storage Regulation. In December 2016, the DOT's Pipeline and Hazardous Materials Safety Administration ("PHMSA") issued an interim final rule ("IFR") that addresses safety issues related to downhole facilities located at both intrastate and interstate underground storage facilities. The IFR incorporates by reference two of the American Petroleum Institute's Recommended Practice standards and mandates certain reporting requirements for operators of underground natural gas storage facilities. Under the IFR, all intrastate transportation related underground natural gas storage facilities will become subject to minimum federal safety standards and be inspected by PHMSA or by a state entity that has chosen to expand its authority to regulate these facilities under a certification filed with PHMSA. The IFR became effective on January 18, 2017, with a compliance deadline of January 18, 2018. PHMSA subsequently determined, however, that it will not issue enforcement citations to any operators for violations of provisions of the IFR that had previously been non-mandatory provisions of American Petroleum Institute Recommended Practices 1170 and 1171 until one year after PHMSA issues a final rule. On October 19, 2017, PHMSA formally reopened the comment period on the IFR in response to a petition for reconsideration. This matter remains ongoing and subject to future PHMSA determinations. We are in compliance with this IFR.

Certain of our field injection and withdrawal wells and water disposal wells are subject to the jurisdiction of the Railroad Commission of Texas ("TRRC"). TRRC regulations require that we report the volumes of natural gas and water disposal associated with the operations of such wells on a monthly and annual basis, respectively. Results of periodic mechanical integrity tests must also be reported to the TRRC. In addition, our underground gas storage caverns in Louisiana are subject to the jurisdiction of the Louisiana Department of Natural Resources ("LDNR"). In recent years, LDNR has put in place more comprehensive regulations governing underground hydrocarbon storage in salt caverns.

We also operate brine disposal wells that are regulated as Class II wells under the federal Safe Drinking Water Act ("SDWA"). The SDWA imposes requirements on owners and operators of Class II wells through the EPA's Underground Injection Control program, including construction, operating, monitoring and testing, reporting and closure requirements. Our brine disposal wells are also subject to comparable state laws and regulations. For more information, see "Environmental Matters" below.

Sales of Natural Gas and NGLs. The prices at which we sell natural gas and NGLs currently are not subject to federal regulation and, for the most part, are not subject to state regulation. Our natural gas and NGL sales are, however, affected by the availability, terms, cost and regulation of pipeline transportation.

Employee Safety. We are subject to the requirements of the Occupational Safety and Health Act ("OSHA"), and comparable state laws that regulate the protection of the health and safety of workers. In addition, the OSHA hazard communication standard requires that information be maintained about hazardous materials used or produced in operations and that this information be provided to employees, state and local government authorities and citizens. We believe that our operations are in substantial compliance with the OSHA requirements including general industry standards, record keeping requirements, and monitoring of occupational exposure to regulated substances.

Pipeline Safety Regulations. Our pipelines are subject to regulation by PHMSA pursuant to the Natural Gas Pipeline Safety Act of 1968 ("NGPSA") and the Pipeline Safety Improvement Act of 2002 ("PSIA"). The NGPSA regulates safety requirements in the design, construction, operation and maintenance of gas pipeline facilities. The PSIA established mandatory inspections for all U.S. crude oil and natural gas transportation pipelines and some gathering lines in high-consequence areas ("HCAs"), which include, among other things, areas of high population density or that serve as sources of drinking water. PHMSA has developed regulations implementing the PSIA that require transportation pipeline operators to implement integrity management programs, including more frequent inspections and other measures to ensure pipeline safety in HCAs. More recently, the Pipeline Safety, Regulatory Certainty and Job Creation Act of 2011 increased penalties for safety violations, established additional safety requirements for newly constructed pipelines and required studies of certain safety issues that could result in the adoption of new regulatory requirements for existing pipelines, and in June 2016, the President of the United States signed the Protecting our Infrastructure of Pipelines and Enhancing Safety Act of 2016 (the "PIPES Act"), which reauthorizes PHMSA's oil and gas pipeline programs through 2019.

In April 2016, PHMSA published a notice of proposed rulemaking ("NPRM"), addressing natural gas transmission and gathering lines. The proposed rule would, among other things, change existing integrity management requirements, expand assessment and repair requirements to pipelines in "moderate-consequence areas," including areas of medium population density, and increase requirements for monitoring and inspection of pipeline segments located outside of HCAs. Furthermore, this NPRM would require that records or other data relied on to determine operating pressures must be traceable, verifiable and complete. Locating such records and, in the absence of any such records, verifying maximum pressures through physical testing or modifying or replacing facilities, could significantly increase our costs. Additionally, failure to locate such records or verify maximum pressures could result in the reduction of allowable operating pressures, which would reduce available capacity on our pipelines. PHMSA, however, has yet to finalize this rulemaking, and the contents and timing of any final rule are currently uncertain.

In addition, in January 2017, PHMSA finalized new hazardous liquid pipeline safety regulations that would have extended certain regulatory reporting requirements to all hazardous liquid gathering (including oil) pipelines. The final rule also would have required additional event-driven and periodic inspections, required the use of leak detection systems on all hazardous liquid pipelines, modified repair criteria, and required certain pipelines to eventually accommodate in-line inspection tools. The effective date of this final rule is currently uncertain due to a regulatory freeze implemented by the Trump administration on January 20, 2017.

On January 23, 2017, PHMSA published in the Federal Register amendments to the pipeline safety regulations to address requirements of the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 and to update and clarify certain regulatory requirements regarding notifications of accidents and incidents. The final rule also adds provisions for cost recovery for design reviews of certain new projects, provides for renewal of existing special permits, and incorporates certain standards for in-line inspections and stress corrosion cracking assessments.

At the state level, several states have passed legislation or promulgated rules dealing with pipeline safety. We believe that our pipeline operations are in substantial compliance with applicable PHMSA and state requirements; however, due to the possibility of new or amended laws and regulations or reinterpretation of existing laws and regulations, there can be no assurance that future compliance with PHMSA or state requirements will not have a material adverse effect on our financial condition, results of operations or cash flows.

On November 2, 2015, PHMSA issued a Notice of Probable Violation and Proposed Compliance Order (the “NOPV”) asserting that we have probable violations of 49 CFR Part 195 due to the misclassification of a transmission line as a gathering line. Transmission lines are subject to more fulsome pipeline safety regulations than gathering lines. The NOPV proposed a compliance order requiring us to satisfy the Part 195 requirements applicable to transmission lines but did not propose a penalty. On January 18, 2018, we received a letter from PHMSA withdrawing the NOPV and indicating that the case was closed effective as of January 18, 2018.

Environmental Matters

General. Our operations involve processing and pipeline services for delivery of hydrocarbons (natural gas, NGLs, crude oil and condensates) from point-of-origin at crude oil and gas wellheads operated by our suppliers to our end-use market customers. Our facilities include natural gas processing and fractionation plants, natural gas and NGL storage caverns, brine disposal wells, pipelines and associated facilities, fractionation and storage units for NGLs, and transportation and delivery of hydrocarbons. As with all companies in our industrial sector, our operations are subject to stringent and complex federal, state and local laws and regulations relating to the discharge of hazardous substances or solid wastes into the environment or otherwise relating to protection of the environment. Compliance with existing and anticipated environmental laws and regulations increases our overall costs of doing business, including costs of planning, constructing, and operating plants, pipelines, and other facilities, as well as capital expenditures necessary to maintain or upgrade equipment and facilities. Similar costs are likely upon changes in laws or regulations and upon any future acquisition of operating assets.

Any failure to comply with applicable environmental laws and regulations, including those relating to equipment failures, and obtaining required governmental approvals and permits, may result in the assessment of administrative, civil or criminal penalties, imposition of investigatory or remedial activities and, in certain, less common circumstances, issuance of temporary or permanent injunctions or construction or operation bans or delays. As part of the regular evaluation of our operations, we routinely review and update governmental approvals as necessary.

The continuing trend in environmental regulation is to place more restrictions and limitations on activities that may affect the environment, and thus there can be no assurance as to the amount or timing of future expenditures for environmental compliance or remediation, and actual future expenditures may be different from the amounts we currently anticipate. Moreover, risks of process upsets, accidental releases or spills are associated with possible future operations, and we cannot assure you that we will not incur significant costs and liabilities, including those relating to claims for damage to the environment, property and persons as a result of any such upsets, releases or spills. We may be unable to pass on current or future environmental costs to our customers. A discharge or release of hydrocarbons, hazardous substances or solid wastes into the environment could, to the extent losses related to the event are not insured, subject us to substantial expense, including both the cost to comply with applicable laws and regulations and to pay fines or penalties that may be assessed and the cost related to claims made by neighboring landowners and other third parties for personal injury or damage to natural resources or property. We attempt to anticipate future regulatory requirements that might be imposed and plan accordingly to comply with changing environmental laws and regulations and to minimize costs with respect to more stringent future laws and regulations or more rigorous enforcement of existing laws and regulations.

Hazardous Substances and Solid Waste. Environmental laws and regulations that relate to the release of hazardous substances or solid wastes into soils, sediments, groundwater and surface water and/or include measures to prevent and control pollution may pose significant costs to our industrial sector. These laws and regulations generally regulate the generation, storage, treatment, transportation and disposal of solid wastes and hazardous substances and may require investigatory and corrective actions at facilities where such waste or substance may have been released or disposed. For instance, the Comprehensive Environmental Response, Compensation, and Liability Act (“CERCLA”), also known as the federal “Superfund” law, and comparable state laws impose liability without regard to fault or the legality of the original conduct on certain classes of persons that contributed to a release of a “hazardous substance” into the environment. Potentially responsible parties include the owner or operator of the site where a release occurred and companies that disposed or arranged for the disposal of the hazardous substances found at an off-site location, such as a landfill. Under CERCLA, these persons may be subject to joint and several liability for the costs of cleaning up and restoring sites where hazardous substances have been released into the environment and for damages to natural resources. CERCLA also authorizes the U.S. Environmental Protection Agency (“EPA”) and, in some cases, third parties, to take actions in response to threats to public health or the environment and to seek recovery of costs they incur from the potentially 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 solid wastes released into the environment. Although petroleum, natural gas and NGLs are excluded from CERCLA's definition of a "hazardous substance," in the course of ordinary operations, we may generate wastes that may fall within the definition of a "hazardous substance." In addition, there are other laws and regulations that can create liability for releases of petroleum, natural gas or NGLs. Moreover, we may be responsible under CERCLA or other laws for all or part of the costs required to clean up sites at which such substances have been disposed. We have not received any notification that we may be potentially responsible for cleanup costs under CERCLA or any analogous federal, state, or local law.

We also generate, and may in the future generate, both hazardous and nonhazardous solid wastes that are subject to requirements of the federal Resource Conservation and Recovery Act ("RCRA") and/or comparable state statutes. From time to time, the EPA and state regulatory agencies have considered the adoption of stricter disposal standards for nonhazardous wastes, including crude oil, condensate and natural gas wastes. Moreover, it is possible that some wastes generated by us that are currently exempted from the definition of hazardous waste may in the future lose this exemption and be designated as "hazardous wastes," resulting in the wastes being subject to more rigorous and costly management and disposal requirements. Additionally, the Toxic Substances Control Act ("TSCA") and analogous state laws impose requirements on the use, storage and disposal of various chemicals and chemical substances. In June 2017, the EPA finalized three rulemakings to update its implementation of TSCA. Two of the new rules establish the EPA's process and criteria for identifying high priority chemicals for risk evaluation and determining whether these high priority chemicals present an unreasonable risk to health or the environment. The third rule requires industry reporting of chemicals manufactured or processed in the U.S. over the past 10 years. Changes in applicable laws or regulations may result in an increase in our capital expenditures or plant operating expenses or otherwise impose limits or restrictions on our production and operations.

We currently own or lease, have in the past owned or leased, and in the future may own or lease, properties that have been used over the years for brine disposal operations, crude oil and condensate transportation, natural gas gathering, treating or processing and for NGL fractionation, transportation or storage. Solid waste disposal practices within the NGL industry and other oil and natural gas related industries have improved over the years with the passage and implementation of various environmental laws and regulations. Nevertheless, some hydrocarbons and other solid wastes may have been released on or under various properties owned, leased or operated by us during the operating history of those properties. In addition, a number of these properties may have been operated by third parties over whose operations and hydrocarbon and waste management practices we had no control. These properties and wastes disposed thereon may be subject to the SWDA, CERCLA, RCRA, TSCA and analogous state laws. Under these laws, we could be required, alone or in participation with others, to remove or remediate previously disposed wastes or property contamination, if present, including groundwater contamination, or to take action to prevent future contamination.

Air Emissions. Our current and future operations are subject to the federal Clean Air Act and regulations promulgated thereunder and under comparable state laws and regulations. These laws and regulations regulate emissions of air pollutants from various industrial sources, including our facilities, and impose various control, monitoring, and reporting requirements. Pursuant to these laws and regulations, we may be required to obtain environmental agency pre-approval for the construction or modification of certain projects or facilities expected to produce air emissions or result in an increase in existing air emissions, obtain and comply with the terms of air permits, which include various emission and operational limitations, or use specific emission control technologies to limit emissions. We likely will be required to incur certain capital expenditures in the future for air pollution control equipment in connection with maintaining or obtaining governmental approvals addressing air emission-related issues. Failure to comply with applicable air statutes or regulations may lead to the assessment of administrative, civil or criminal penalties and may result in the limitation or cessation of construction or operation of certain air emission sources or require us to incur additional capital expenditures. Although we can give no assurances, we believe such requirements will not have a material adverse effect on our financial condition, results of operations or cash flows, and the requirements are not expected to be more burdensome to us than to any similarly situated company.

In addition, the EPA included Wise County, the location of our Bridgeport facility, in its January 2012 revision to the Dallas-Fort Worth ozone nonattainment area for the 2008 revised ozone national ambient air quality standard ("NAAQS"). As a result of this moderate nonattainment designation, new major sources in Wise County, meaning sources that emit greater than 100 tons/year of nitrogen oxides ("NOx") and volatile organic compounds ("VOCs"), as well as major modifications of existing facilities in the county resulting in net emissions increases of greater than 40 tons/year of NOx or VOCs, are subject to more stringent new source review ("NSR") pre-construction permitting requirements than they would be in an area that is in attainment with the 2008 ozone NAAQS. NSR pre-construction permits can take twelve to eighteen months to obtain and require the permit applicant to offset the proposed emission increases with reductions elsewhere at a 1.15 to 1 ratio. In October 2015, the EPA lowered the NAAQS for ozone from 75 to 70 parts per billion for both the 8-hour primary and secondary standards. This new standard is being challenged in a pending appeal before the U.S. Court of Appeals for the D.C. Circuit, but if the standard is implemented, it could result in stricter permitting requirements, delay or prohibit our ability to obtain such permits, and result in potentially significant expenditures for pollution control equipment.

Effective May 15, 2012, the EPA promulgated rules under the Clean Air Act that established new air emission controls for oil and natural gas production, pipelines and processing operations under the New Source Performance Standards (“NSPS”) and National Emission Standards for Hazardous Air Pollutants (“NESHAPs”) programs. These rules require the control of emissions through reduced emission (or “green”) completions and establish specific new requirements regarding emissions from wet seal and reciprocating compressors, pneumatic controllers, and storage vessels at production facilities, gathering systems, boosting facilities, and onshore natural gas processing plants. In addition, the rules revised existing requirements for VOC emissions from equipment leaks at onshore natural gas processing plants by lowering the leak definition for valves from 10,000 parts per million to 500 parts per million and requiring the monitoring of connectors, pumps, pressure relief devices and open-ended lines. These rules required a number of modifications to our assets and operations. In October 2012, several challenges to the EPA’s NSPS and NESHAPs rules for the industry were filed by various parties, including environmental groups and industry associations. In a January 16, 2013 unopposed motion to hold this litigation in abeyance, the EPA indicated that it may reconsider some aspects of the rules. The case remains in abeyance. The EPA has since revised certain aspects of the rules and has indicated that it may reconsider other aspects of the rules. Depending on the outcome of such proceedings, the rules may be further modified or rescinded or the EPA may issue new rules. We cannot predict the costs of compliance with any modified or newly issued rules.

In partial response to the issues raised regarding the 2012 rulemaking, the EPA recently finalized new rules that took effect August 2, 2016 to regulate emissions of methane and VOCs from new and modified sources in the oil and gas sector. The EPA announced its intention to reconsider those regulations in April 2017 and has sought to stay its requirements. However, the rule remains in effect. In June 2016, the EPA also finalized a rule regarding alternative criteria for aggregating multiple small surface sites into a single source for air quality permitting purposes. This rule could cause small facilities within one-quarter mile of one another to be deemed a major source on an aggregate basis, thereby triggering more stringent air permitting processes and requirements across the oil and gas industry. On November 10, 2016, the EPA issued a final Information Collection Request (“ICR”) that requires numerous oil and gas companies to provide information regarding methane emissions from existing oil and gas facilities, a step used to provide a basis for future rulemaking. The EPA withdrew this ICR in March 2017. The Obama Administration indicated that other federal agencies, including the Bureau of Land Management (“BLM”), PHMSA, and the Department of Energy would be imposing new or more stringent regulations on the oil and gas sector in order to further reduce methane emissions. For example, the BLM adopted new rules on November 15, 2016, to be effective on January 17, 2017, to reduce venting, flaring, and leaks during oil and natural gas production activities on onshore federal and Indian leases. Certain provisions of the BLM rule went into effect in January 2017, while others were scheduled to go into effect in January 2018. In December 2017, BLM published a final rule delaying the 2018 provisions until 2019. As a result of this continued regulatory focus and other factors, additional GHG regulation of the oil and gas industry remains possible. Compliance with such rules could result in additional costs, including increased capital expenditures and operating costs for us and for other companies in our industry. While we are not able at this time to estimate such additional costs, as is the case with similarly situated entities in the industry, they could be significant for us. Compliance with such rules, as well as any new state rules, may also make it more difficult for our suppliers and customers to operate, thereby reducing the volume of natural gas transported through our pipelines, which may adversely affect our business. However, the status of recent and future rules and rulemaking initiatives under the Trump Administration remains uncertain.

Climate Change. In December 2009, the EPA determined that emissions of certain gases, commonly referred to as “greenhouse gases,” present an endangerment to public health and the environment because emissions of such gases are, according to the EPA, contributing to the warming of the earth’s atmosphere and other climatic changes. Based on these findings, the EPA adopted regulations under existing provisions of the federal Clean Air Act that require Prevention of Significant Deterioration (“PSD”) pre-construction permits and Title V operating permits for greenhouse gas emissions from certain large stationary sources. Under these regulations, facilities required to obtain PSD permits must meet “best available control technology” standards for their greenhouse gas emissions established by the states or, in some cases, by the EPA on a case by case basis. The EPA has also adopted rules requiring the monitoring and reporting of greenhouse gas emissions from specified sources in the United States, including, among others, certain onshore oil and natural gas processing and fractionating facilities. The EPA announced its intention to reconsider those regulations in April 2017 and has sought to stay its requirements. However, the rule remains in effect. In addition, 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. Because regulation of greenhouse gas emissions is relatively new, further regulatory, legislative and judicial developments are likely to occur. Such developments in greenhouse gas initiatives may affect us and other companies operating in the oil and gas industry. In addition to these developments, recent judicial decisions have allowed certain tort claims alleging property damage to proceed against greenhouse gas emissions sources, which may increase our litigation risk for such claims. In addition, 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 entered into force November 4, 2016, and requires 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. In June 2017, the Trump Administration announced its intent to withdraw from the Paris Agreement. Pursuant to the terms of the Paris Agreement, the earliest date the United States can withdraw is November 2020. Due to the uncertainties surrounding the regulation of and other risks associated with greenhouse gas emissions, we cannot predict the financial impact of related developments on us.

Federal or state legislative or regulatory initiatives that regulate or restrict emissions of greenhouse gases in areas in which we conduct business could adversely affect the availability of, or demand for, the products we store, transport and process, and, depending on the particular program adopted, could increase the costs of our operations, including costs to operate and maintain our facilities, install new emission controls on our facilities, acquire allowances to authorize our greenhouse gas emissions, pay any taxes related to our greenhouse gas emissions and/or administer and manage a greenhouse gas emissions program. We may be unable to recover any such lost revenues or increased costs in the rates we charge our customers, and any such recovery may depend on events beyond our control, including the outcome of future rate proceedings before FERC or state regulatory agencies and the provisions of any final legislation or regulations. Reductions in our revenues or increases in our expenses as a result of climate control initiatives could have adverse effects on our business, financial condition, results of operations or cash flows.

Due to their location, our operations along the Gulf Coast are vulnerable to operational and structural damages resulting from hurricanes and other severe weather systems, while inland operations include areas subject to tornadoes. Our insurance may not cover all associated losses. We are taking steps to mitigate physical risks from storms, but no assurance can be given that future storms will not have a material adverse effect on our business.

Hydraulic Fracturing and Wastewater. The Federal Water Pollution Control Act, also known as the Clean Water Act, and comparable state laws impose restrictions and strict controls regarding the discharge of pollutants, including NGL-related wastes, into state waters or waters of the United States. In June 2015, the EPA and the U.S. Army Corps of Engineers finalized a rule intended to clarify the meaning of the term “waters of the United States,” which establishes the scope of regulated waters under the Clean Water Act. The rule has been challenged and was stayed by federal courts. Absent Congressional action, the rule will become applicable if the courts do not continue the stay of the rule during the litigation; if upheld, the rule is expected to expand federal jurisdiction under the Clean Water Act. In November 2017, the EPA and the U.S. Army Corps of Engineers proposed the addition of an applicability date to the 2015 Clean Water Rule that would be two years after the date of a final rule. This change, if adopted, would effectively prevent the rule from coming back into effect immediately if the stay is lifted. Regulations promulgated pursuant to the Clean Water Act require that entities that discharge into federal and state waters obtain National Pollutant Discharge Elimination System (“NPDES”) permits and/or state permits authorizing these discharges. The Clean Water Act and analogous state laws assess administrative, civil and criminal penalties for discharges of unauthorized pollutants into the water and impose substantial liability for the costs of removing spills from such waters. In addition, the Clean Water Act and analogous state laws require that individual permits or coverage under general permits be obtained by covered facilities for discharges of storm water runoff. We believe that we are in substantial compliance with Clean Water Act permitting requirements as well as the conditions imposed by our permits and that continued compliance with such existing permit conditions will not have a material effect on our financial condition, results of operations or cash flows.

In December 2016, the EPA released the final results of its comprehensive research study on the potential adverse impacts that hydraulic fracturing may have on drinking water resources. The EPA concluded that hydraulic fracturing activities can impact drinking water resources under some circumstances, including large volume spills and inadequate mechanical integrity of wells. The results of the EPA’s study could spur action toward federal legislation and regulation of hydraulic fracturing or similar production operations. We operate brine disposal wells that are regulated as Class II wells under the SDWA. The SDWA imposes requirements on owners and operators of Class II wells through the EPA’s Underground Injection Control program, including construction, operating, monitoring and testing, reporting and closure requirements. Our brine disposal wells are also subject to comparable state laws and regulations, which in some cases are more stringent than requirements under the SDWA, such as the Ohio Department of Natural Resources rules that took effect October 1, 2012. These rules set new, more stringent standards for the permitting and operating of brine disposal wells, including extensive review of geologic data and use of state-of-the-art technology. The Ohio Department of Natural Resources also imposes requirements on the transportation and disposal of brine. Compliance with current and future laws and regulations regarding our brine disposal wells may impose substantial costs and restrictions on our brine disposal operations, as well as adversely affect demand for our brine disposal services. State and federal regulatory agencies recently have focused on a possible connection between the operation of injection wells used for oil and gas waste waters and an observed increase in minor seismic activity and tremors. When caused by human activity, such events are called induced seismicity. In a few instances, operators of injection wells in the vicinity of minor seismic events have reduced injection volumes or suspended operations, often voluntarily. A 2012 report published by the National Academy of Sciences concluded that only a very small fraction of the tens of thousands of injection wells have been suspected to be, or have been, the likely cause of induced seismicity. However, some state regulatory agencies have modified their regulations to account for induced seismicity. For example, TRRC rules allow the TRRC to modify, suspend, or terminate a permit based on a determination that the permitted activity is likely to be contributing to seismic activity. In the state of Ohio, the Ohio Department of Natural Resources ("ODNR") requires a seismic study prior to the authorization of any new disposal well. In addition, the ODNR has instituted a continuous monitoring network of seismographs and is able to curtail injected volumes regionally based upon seismic activity detected. The Oklahoma Corporation Commission ("OCC") has also taken steps to focus on induced seismicity, including increasing the frequency of required recordkeeping for wells that dispose into certain formations and considering seismic information in permitting decisions. For instance, on August 3, 2015, the OCC adopted a plan calling for mandatory reductions in oil and gas wastewater disposal well volumes, the implementation of which has involved reductions of injection or shut-ins of disposal wells. The OCC also recently released well completion seismicity guidelines in December 2016 for operators in the STACK play that call for hydraulic fracturing operations to be suspended following earthquakes of certain magnitudes in the vicinity. Regulatory agencies are continuing to study possible linkage between injection activity and induced seismicity. To the extent these studies result in additional regulation of injection wells, such regulations could impose additional regulations, costs and restrictions on our brine disposal operations.

It is common for our customers or suppliers to recover natural gas from deep shale formations through the use of hydraulic fracturing, combined with sophisticated horizontal drilling. Hydraulic fracturing is an important and commonly used process in the completion of wells by oil and gas producers. Hydraulic fracturing involves the injection of water, sand and chemical additives under pressure into rock formations to stimulate gas production. Due to public concerns raised regarding potential impacts of hydraulic fracturing on groundwater quality, legislative and regulatory efforts at the federal level and in some states and localities have been initiated to require or make more stringent the permitting and other regulatory requirements for hydraulic fracturing operations of our customers and suppliers. There are certain governmental reviews either underway or being proposed that focus on environmental aspects of hydraulic fracturing practices. On December 13, 2016, the EPA released a study of the potential adverse effects that hydraulic fracturing may have on water quality and public health, concluding that there is scientific evidence that hydraulic fracturing activities potentially can impact drinking water resources in the United States under some circumstances. This study or similar studies could spur initiatives to further regulate hydraulic fracturing. In June 2016, the EPA finalized rules prohibiting discharges of wastewater from hydraulic fracturing operations to publicly owned wastewater treatment plants. The EPA has also issued an advance notice of proposed rulemaking under the Toxic Substances Control Act to gather information regarding the potential regulation of chemical substances and mixtures used in oil and gas exploration and production. Also, effective June 24, 2015, BLM adopted rules regarding well stimulation, chemical disclosures, water management, and other requirements for hydraulic fracturing on federal and American Indian lands; however, a federal district court invalidated these BLM rules in June 2016, but the rules were reinstated on appeal by the U.S. Court of Appeals for the Tenth Circuit in September 2017. While this appeal was pending, BLM proposed a rulemaking in July 2017 to rescind these rules in their entirety. BLM has yet to finalize this rulemaking. Additional regulatory burdens in the future, whether federal, state or local, could increase the cost of or restrict the ability of our customers or suppliers to perform hydraulic fracturing. As a result, any increased federal, state or local regulation could reduce the volumes of natural gas that our customers move through our gathering systems which would materially adversely affect our financial condition, results of operations or cash flows.

Endangered Species and Migratory Birds. The Endangered Species Act ("ESA"), Migratory Bird Treaty Act ("MBTA"), and similar state and local laws restrict activities that may affect endangered or threatened species or their habitats or migratory birds. Some of our pipelines may be located in areas that are designated as habitats for endangered or threatened species, potentially exposing us to liability for impacts on an individual member of a species or to habitat. The ESA can also make it more difficult to secure a federal permit for a new pipeline.

Office Facilities

We occupy approximately 157,600 square feet of space at our executive offices in Dallas, Texas under a lease expiring in February 2030. We also occupy office space of approximately 56,000 square feet in Midland, Texas and 32,000 square feet in Houston, Texas under long-term leases.

Employees

As of December 31, 2017, we (through our subsidiaries) employed 1,494 full-time employees. Of these employees, 330 were general and administrative, engineering, accounting and commercial personnel, and the remainder were operational employees. We are not party to any collective bargaining agreements and we have not had any significant labor disputes in the past. We believe that we have good relations with our employees.

Item 1A. Risk Factors

The following risk factors and all other information contained in this report should be considered carefully when evaluating us. These risk factors could affect our actual results. Other risks and uncertainties, in addition to those that are described below, may also impair our business operations. If any of the following risks occur, our business, financial condition, results of operations or cash flows (including our ability to make distributions to our noteholders) could be affected materially and adversely. In that case, we may be unable to make distributions to our unitholders, and the trading price of our common units could decline. These risk factors should be read in conjunction with the other detailed information concerning us set forth in our accompanying financial statements and notes and contained in "*Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations*" *included herein.*

We are dependent on Devon for a substantial portion of the natural gas that we gather, process and transport. The expiration of five-year MVCsfrom Devon in 2019 and 2020 could result in a material decline in our operating results and cash available for distribution because the volumes of natural gas that we gathered, processed and transported for Devon during 2017 have been below the MVC levels under certain of our contracts.

We are dependent on Devon for a substantial portion of our natural gas supply. For the year endedDecember 31, 2017, Devon represented approximately 46.8% of our gross operating margin. In order to minimize volumetric exposure, in March 2014, we obtained five-year MVCs from Devon at the Bridgeport processing facility, Bridgeport and East Johnson County gathering systems and the Central Oklahoma gathering system, and these MVCs expire on January 1, 2019. We also have a five-year MVC from Devon attributable to VEX, and this MVC expires on July 31, 2019. If the volumes of natural gas and crude oil that we gather and transport on our systems are below the MVC levels after the contracts expire, we could experience a material decline in our operating revenues and cash flow. For the year ended December 31, 2017, we recognized $59.2 million, $13.8 million and $8.9 million in MVC shortfall revenue from Devon attributable to our Texas, Oklahoma and Crude and Condensate segments, respectively, because volumes were below the minimum level. For the year ended December 31, 2016, we recognized $26.4 million, $10.8 million and $9.0 million in MVC shortfall revenue from Devon attributable to our Texas, Oklahoma and Crude and Condensate segments, respectively. For the year ended December 31, 2015, we recognized $3.8 million, $20.1 million, and $0.5 million in MVC shortfall revenue from Devon attributable to our Texas, Oklahoma and Crude and Condensate segments, respectively.

Because we are substantially dependent on Devon as one of our primary customers and through its indirect control of our general partner, any development that materially and adversely affects Devon's operations, financial condition or market reputation could have a material and adverse impact on us. Material adverse changes at Devon could restrict our access to capital, make it more expensive to access the capital markets or increase the costs of our borrowings.

We are substantially dependent on Devon as one of our primary customers and through its indirect control of our general partner, and we expect to derive a significant portion of our gross operating margin from Devon for the foreseeable future. As a result, any event, whether in our area of operations or otherwise, that adversely affects Devon's production, financial condition, leverage, market reputation, liquidity, results of operations or cash flows may adversely affect our revenues and cash available for distribution. Accordingly, we are indirectly subject to the business risks of Devon, some of which are the following:

- potential changes in the supply of and demand for oil, natural gas and NGLs and related products and services;
- risks relating to Devon's exploration and drilling programs, including potential environmental liabilities;
- adverse effects of governmental and environmental regulation; and
- general economic and financial market conditions.

Further, we are subject to the risk of non-payment or non-performance by Devon, including with respect to our gathering and processing agreements. We cannot predict the extent to which Devon's business will be impacted by pricing conditions in the energy industry, nor can we estimate the impact such conditions would have on Devon's ability to perform under our gathering and processing agreements. Additionally, due to our relationship with Devon, our ability to access the capital markets, or the pricing or other terms of any capital markets transactions, may be adversely affected by any impairments to Devon's financial condition or adverse changes in its credit ratings. S&P Global Ratings ("S&P") and Moody's Investors Services ("Moody's") have currently assigned to Devon a BBB and Ba1 credit rating, respectively. Any material limitations on our ability to access capital as a result of such adverse changes at Devon could limit our ability to obtain future financing under favorable terms, or at all, or could result in increased financing costs in the future. Similarly, material adverse changes at Devon could negatively impact our unit price, limiting our ability to raise capital through equity issuances or debt financing or our ability to engage in, expand or pursue our business activities and could also prevent us from engaging in certain transactions that might otherwise be considered beneficial to us.

Please see "Item 1A. Risk Factors" in Devon's Annual Report on Form 10-K for the year ended December 31, 2017 for a full discussion of the risks associated with Devon's business.

Devon may compete with us.

Devon may compete with us, including by developing or acquiring additional gathering and processing assets. Pursuant to the terms of our operating agreement, the doctrine of corporate opportunity, or any analogous doctrine, does not apply to our general partner or any of its affiliates, including Devon and its executive officers and directors. 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 of our members 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 unitholders.

Adverse developments in our gathering, transmission, processing, crude oil, condensate, natural gas and NGL services businesses would reduce our ability to make distributions to our unitholders.

We rely exclusively on the revenues generated from our gathering, transmission, processing, fractionation, crude oil, natural gas, condensate and NGL services businesses, and as a result, our financial condition depends upon prices of, and continued demand for, natural gas, NGLs, crude oil and condensate. An adverse development in one of these businesses may have a significant impact on our financial condition and our ability to make distributions to our unitholders.

A significant portion of our operations are located in the Barnett Shale, making us vulnerable to risks associated with having revenue-producing operations concentrated in a limited number of geographic areas.

Our revenue-producing operations are geographically concentrated in the Barnett Shale, causing us to be exposed to risks associated with regional factors. Specifically, our operations in the Barnett Shale accounted for approximately 11.9% of our consolidated revenues and approximately 34.1% of our consolidated gross operating margin for the year ended December 31, 2017. The concentration of our operations in this region also increases exposure to unexpected events that may occur in this region such as natural disasters or labor difficulties. Any one of these events has the potential to have a relatively significant impact on our operations and growth plans, decrease cash flows, increase operating and capital costs and prevent development within originally anticipated time frames. Any of these risks could have a material adverse effect on our financial condition, results of operations or cash flows.

We must continually compete for crude oil, condensate, natural gas and NGL supplies, and any decrease in supplies of such commodities could adversely affect our financial condition, results of operations or cash flows.

In order to maintain or increase throughput levels in our gathering systems and asset utilization rates at our processing plants and fractionators, we must continually contract for new product supplies. We may not be able to obtain additional contracts for crude oil, condensate, natural gas and NGL supplies. The primary factors affecting our ability to connect new wells to our gathering facilities include our success in contracting for existing supplies that are not committed to other systems and the level of drilling activity near our gathering systems. If we are unable to maintain or increase the volumes on our systems by accessing new supplies to offset the natural decline in reserves, our business and financial results could be materially, adversely affected. In addition, our future growth will depend in part upon whether we can contract for additional supplies at a greater rate than the rate of natural decline in our current supplies.

Fluctuations in energy prices can greatly affect production rates and investments by third parties in the development of new crude oil, condensate and natural gas reserves. During 2015 and 2016, we saw suppressed drilling activity due to low commodity prices. Although drilling activity has improved during 2017 in some of the most economic basins, we could see downward pressure on future drilling activity in these basins if commodity prices decline below current levels, which may result in lower volumes. Tax policy changes or additional regulatory restrictions on development could also have a negative impact on drilling activity, reducing supplies of product available to our systems and assets. Additional governmental regulation of, or delays in issuance of permits for, the offshore exploration and production industry may negatively impact current and future volumes from offshore pipelines supplying our processing plants. We have no control over producers and depend on them to maintain sufficient levels of drilling activity. A continued decrease in the level of drilling activity or a material decrease in production in our principal geographic areas for a prolonged period, as a result of unfavorable commodity prices or otherwise, likely would have a material adverse effect on our financial condition, results of operations and cash flows.

Any decrease in the volumes that we gather, process, fractionate or transport would adversely affect our financial condition, results of operations or cash flows.

Our financial performance depends to a large extent on the volumes of natural gas, crude oil, condensate and NGLs gathered, processed, fractionated and transported on our assets. Decreases in the volumes of natural gas, crude oil, condensate and NGLs we gather, process, fractionate or transport would directly and adversely affect our financial condition. These volumes can be influenced by factors beyond our control, including:

- environmental or other governmental regulations;
- weather conditions;
- increases in storage levels of natural gas, NGLs, crude oil and condensate;
- increased use of alternative energy sources;
- decreased demand for natural gas, NGLs, crude oil and condensate;
- continued fluctuations in commodity prices, including the prices of natural gas, NGLs, crude oil and condensate;
- economic conditions;
- supply disruptions;
- availability of supply connected to our systems; and
- availability and adequacy of infrastructure to gather and process supply into and out of our systems.

The volumes of natural gas, crude oil, condensate and NGLs gathered, processed, fractionated and transported on our assets also depend on the production from the regions that supply our systems. Supply of natural gas, crude oil, condensate and NGLs can be affected by many of the factors listed above, including commodity prices and weather. In order to maintain or increase throughput levels on our systems, we must obtain new sources of natural gas, crude oil, condensate and NGLs. The primary factors affecting our ability to obtain non-dedicated sources of natural gas, crude oil, condensate and NGLs include (i) the level of successful leasing, permitting and drilling activity in our areas of operation, (ii) our ability to compete for volumes from new wells and (iii) our ability to compete successfully for volumes from sources connected to other pipelines. 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, we have no control over producers or their drilling or production decisions, which are affected by, among other things, the availability and cost of capital, levels of reserves, availability of drilling rigs and other costs of production and equipment.

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

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. For the investments we account for under the equity method, the impairment test considers whether the fair value of the unconsolidated affiliate 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. For the year ended December 31, 2015, we recognized impairments on property and equipment of $12.1 million, an intangible asset impairment of $223.1 million and a goodwill impairment of $1,328.2 million. In the first quarter of 2016, we recognized an additional goodwill impairment of $566.3 million. For the year ended December 31, 2017, we recognized impairments on property and equipment of $17.1 million. Additional impairment of the value of our existing goodwill and intangible assets could have a significant negative impact on our future operating results.

Our construction of new assets may be more expensive than anticipated, may not result in revenue increases and may be subject to regulatory, environmental, political, legal and economic risks that could adversely affect our financial condition, results of operations or cash flows.

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 beyond our control including potential protests or legal actions by interested third parties, and may require the expenditure of significant amounts of capital. Financing may not be available on economically acceptable terms or at all. If we undertake these projects, we may not be able to complete them on schedule, at the budgeted cost or at all. Moreover, our revenues may not increase due to the successful construction of a particular project. For instance, if we expand a 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 promptly following completion of a project or at all. Moreover, we may construct facilities to capture anticipated future production growth in a region in which such growth does not materialize. As a result, new facilities may not be able to attract enough throughput to achieve our expected investment return, which could adversely affect our financial condition, results of operations or cash flows. In addition, the construction of additions to our existing gathering and processing assets will generally require us to obtain new rights-of-way and permits prior to constructing new pipelines or facilities. We may be unable to timely obtain such rights-of-way or permits to connect new product supplies to our existing gathering lines or capitalize on other attractive expansion opportunities. Additionally, it may become more expensive for us to obtain new rights-of-way or to expand or renew existing rights-of-way. If the cost of renewing or obtaining new rights-of-way increases, our cash flows could be adversely affected.

Construction of our major development projects subjects us to risks of construction delays, cost over-runs, limitations on our growth and negative effects on our financial condition, results of operations or cash flows.

We are engaged in the planning and construction of several major development projects, some of which will take a number of months before commercial operation. These projects are complex and subject to a number of factors beyond our control, including delays from vendors, suppliers and third-party landowners, the permitting process, changes in laws, unavailability of materials, labor disruptions, environmental hazards, financing, accidents, weather and other factors. Any delay in the completion of these projects could have a material adverse effect on our financial condition, results of operations or cash flows. The construction of pipelines and gathering and processing and fractionation facilities requires the expenditure of significant amounts of capital, which may exceed our estimated costs. Estimating the timing and expenditures related to these development projects is very complex and subject to variables that can significantly increase expected costs. Should the actual costs of these projects exceed our estimates, our liquidity and capital position could be adversely affected. This level of development activity requires significant effort from our management and technical personnel and places additional requirements on our financial resources. We may not have the ability to attract and/or retain the necessary number of personnel with the skills required to bring complicated projects to successful conclusions.

Our operations are dependent on our rights and ability to receive or renew the required permits and other approvals from governmental authorities and other third parties.

Performance of our operations requires that we obtain and maintain numerous environmental and land use permits and other approvals authorizing our business activities. A decision by a governmental authority or other third party to deny, delay or restrictively condition the issuance of a new or renewed permit or other approval, or to revoke or substantially modify an existing permit or other approval, could have a material adverse effect on our ability to initiate or continue operations at the affected location or facility. Expansion of our existing operations is also predicated on securing the necessary environmental or land use permits and other approvals, which we may not receive in a timely manner or at all.

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 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 needed to develop a site or pipeline alignment. Also, obtaining or renewing required permits or other approvals is sometimes delayed or prevented due to community opposition and other factors beyond our control. The denial of a permit or other approvals essential to our operations or the imposition of restrictive conditions with which it is not practicable or feasible to comply could impact our operations or prevent our ability to expand our operations or obtain rights-of-way. Significant opposition to a permit or other approvals by neighboring property owners, members of the public or non-governmental organizations, or other third parties or delays in the environmental review and permitting process also could impact our operations or prevent our ability to expand our operations or obtain rights-of-way.

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

We participate in several joint ventures, and we may enter into other joint venture arrangements in the future. The nature of a joint venture requires us to share control with unaffiliated third parties. If our joint venture partners do not fulfill their contractual and other obligations, the affected joint venture may be unable to operate according to its business plan, and we may be required to increase our level of commitment. If we do not timely meet our financial commitments or otherwise comply with our joint venture agreements, our ownership of and rights with respect to the applicable joint venture may be reduced or otherwise adversely affected. Differences in views among joint venture participants could also result in delays in business decisions or otherwise, failures to agree on major issues, operational inefficiencies and impasses, litigation or other issues. Third parties may also seek to hold us liable for the joint ventures' liabilities. These issues or any other difficulties that cause a joint venture to deviate from its original business plan could have a material adverse effect on our financial condition, results of operations or cash flows.

Any reductions in our credit ratings could increase our financing costs, the cost of maintaining certain contractual relationships and reduce our cash available for distribution.

We cannot guarantee 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 so warrant. S&P and Moody's have currently assigned to ENLK a BBB- and Ba1 credit rating, respectively. Any future downgrade could increase the cost of borrowings under our credit facility. Any downgrade could also lead to higher borrowing costs for future borrowings and, if below investment grade, could require:

- additional or more restrictive covenants that impose operating and financial restrictions on us and our subsidiaries;
- our subsidiaries to guarantee such debt and certain other debt;
- us and our subsidiaries to provide collateral to secure such debt; and
- us or our subsidiaries to post cash collateral or letters of credit under our hedging arrangements or in order to purchase commodities or obtain trade credit.

Any increase in our financing costs or additional or more restrictive covenants resulting from a credit rating downgrade could adversely affect our ability to finance future operations and make cash distributions to unitholders. If a credit rating downgrade and the resultant collateral requirement were to occur at a time when we were experiencing significant working capital requirements or otherwise lacked liquidity, our results of operations and our ability to make cash distributions to unitholders could be adversely affected.

We typically do not obtain independent evaluations of hydrocarbon reserves; therefore, volumes we service in the future could be less than we anticipate.

We typically do not obtain, on a regular basis, independent evaluations of hydrocarbon reserves connected to our gathering systems or that we otherwise service due to the unwillingness of producers to provide reserve information as well as the cost of such evaluations. Accordingly, we do not have independent estimates of total reserves serviced by our assets or the anticipated life of such reserves. If the total reserves or estimated life of the reserves is less than we anticipate and we are unable to secure additional sources, then the volumes transported on our gathering systems or that we otherwise service in the future could be less than anticipated. A decline in the volumes could have a material adverse effect on our financial condition, results of operations or cash flows.

We may not be successful in balancing our purchases and sales.

We are a party to certain long-term gas, NGL and condensate sales commitments that we satisfy through supplies purchased under long-term gas, NGL and condensate purchase agreements. When we enter into those arrangements, our sales obligations generally match our purchase obligations. However, over time, the supplies that we have under contract may decline due to reduced drilling or other causes, and we may be required to satisfy the sales obligations by purchasing additional gas at prices that may exceed the prices received under the sales commitments. In addition, a producer could fail to deliver contracted volumes or deliver in excess of contracted volumes, or a consumer could purchase more or less than contracted volumes. Any of these actions could cause our purchases and sales not to be balanced. If our purchases and sales are not balanced, we will face increased exposure to commodity price risks and could have increased volatility in our operating income.

We have made commitments to purchase natural gas in production areas based on production-area indices and to sell the natural gas into market areas based on market-area indices, pay the costs to transport the natural gas between the two points and capture the difference between the indices as margin. Changes in the index prices relative to each other (also referred to as basis spread) can significantly affect our margins or even result in losses. For example, we are a party to one contract associated with our North Texas operations with a term to July 2019 to supply approximately 150,000 MMBtu/d of gas. We buy gas for this contract on several different production-area indices and sell the gas into a different market area index. We realize a loss on the delivery of gas under this contract each month based on current prices. As of December 31, 2017, the balance sheet reflected a liability of $26.9 million related to this performance obligation based on forecasted discounted cash obligations in excess of market under this gas delivery contract. Reduced supplies and narrower basis spreads in recent periods have increased the losses on this contract, and greater losses on this contract could occur in future periods if these conditions persist or become worse.

Our profitability is dependent upon prices and market demand for crude oil, condensate, natural gas and NGLs that are beyond our control and have been volatile. A depressed commodity price environment could result in financial losses and reduce our cash available for distribution.

We are subject to significant risks due to fluctuations in commodity prices. We are directly exposed to these risks primarily in the gas processing and NGL fractionation components of our business. For the year ended December 31, 2017, approximately 3.4% of our total gross operating margin was generated under percent of liquids contracts and percent of proceeds contracts, with most of these contracts relating to our processing plants in the Permian Basin. Under percent of liquids contracts, we receive a fee in the form of a percentage of the liquids recovered, and the producer bears all the cost of the natural gas shrink. Accordingly, our revenues under percent of liquids contracts are directly impacted by the market price of NGLs. Gross operating margin under percent of proceeds contracts is impacted only by the value of the natural gas or liquids produced with margins higher during periods of higher natural gas and liquids prices.

We also realize gross operating margins under processing margin contracts. For the year ended December 31, 2017, approximately1.3% of our total gross operating margin was generated under processing margin contracts. We have a number of processing margin contracts for activities at our Plaquemine and Pelican processing plants. Under this type of contract, we pay the producer for the full amount of inlet gas to the plant, and we make a margin based on the difference between the value of liquids recovered from the processed natural gas as compared to the value of the natural gas volumes lost ("shrink") and the cost of fuel used in processing. The shrink and fuel losses are referred to as plant thermal reduction ("PTR"). Our margins from these contracts can be greatly reduced or eliminated during periods of high natural gas prices relative to liquids prices.

We are also indirectly exposed to commodity prices due to the negative impacts of low commodity prices on production and the development of production of crude oil, condensate, natural gas and NGLs connected to or near our assets and on our margins for transportation between certain market centers. Low prices for these products have reduced the demand for our services and volumes on our systems, and continued low prices may reduce such demand even further.

Although the majority of our NGL fractionation business is under fee-based arrangements, a portion of our business is exposed to commodity price risk because we realize a margin due to product upgrades associated with our Louisiana fractionation business. For the year ended December 31, 2017, gross operating margin realized associated with product upgrades represented approximately 1.3% of our gross operating margin.

The prices of crude oil, condensate, natural gas and NGLs were volatile during2017. Crude oil and weighted average NGL prices increased 15% and 21%, while natural gas prices decreased 11%, from January 1, 2017 to December 31, 2017, respectively. We expect this volatility to continue. For example, crude oil prices (based on the NYMEX futures daily close prices for the prompt month) in 2017 ranged from a high of $60.42 per Bbl in December 2017 to a low of $42.53 per Bbl in June 2017. Weighted average NGL prices in 2017 (based on the Oil Price Information Service ("OPIS") Napoleonville daily average spot liquids prices) ranged from a high of $0.78 per gallon in February 2017 to a low of $0.41 per gallon in January 2017. Natural gas prices (based on Gas Daily Henry Hub closing prices) during 2017 ranged from a high of $3.42 per MMBtu in May 2017 to a low of $2.56 per MMBtu in February 2017.

The markets and prices for crude oil, condensate, natural gas and NGLs depend upon factors beyond our control that make it difficult to predict future commodity price movements with any certainty. These factors include the supply and demand for crude oil, condensate, natural gas and NGLs, which fluctuate with changes in market and economic conditions and other factors, including:

- the impact of weather on the supply and demand for crude oil and natural gas;
- the level of domestic crude oil, condensate and natural gas production;
- technology, including improved production techniques (particularly with respect to shale development);
- the level of domestic industrial and manufacturing activity;
- the availability of imported crude oil, natural gas and NGLs;
- international demand for crude oil and NGLs;
- actions taken by foreign crude oil and gas producing nations;
- the continued threat of terrorism and the impact of military action and civil unrest;

- the availability of local, intrastate and interstate transportation systems;
- the availability of downstream NGL fractionation facilities;
- the availability and marketing of competitive fuels;
- the impact of energy conservation efforts; and
- the extent of governmental regulation and taxation, including the regulation of hydraulic fracturing and “greenhouse gases.”

Changes in commodity prices also indirectly impact our profitability by influencing drilling activity and well operations, and thus the volume of gas, crude oil and condensate we gather and process and NGLs we fractionate. Volatility in commodity prices may cause our gross operating margin and cash flows to vary widely from period to period. Our hedging strategies may not be sufficient to offset price volatility risk and, in any event, do not cover all of our throughput volumes. Moreover, hedges are subject to inherent risks, which we describe in “Item 7A. Quantitative and Qualitative Disclosure about Market Risk.” Our use of derivative financial instruments does not eliminate our exposure to fluctuations in commodity prices and interest rates and has (in the past) resulted and could (in the future) result in financial losses or reductions in our income.

If third-party pipelines or other midstream facilities interconnected to our gathering or transportation systems become partially or fully unavailable, or if the volumes we gather, process or transport do not meet the quality requirements of the pipelines or facilities to which we connect, our gross operating margin and cash flow could be adversely affected.

Our gathering, processing and transportation assets connect to other pipelines or facilities owned and operated by unaffiliated third parties. The continuing operation of, and our continuing access to, such third-party pipelines, processing facilities and other midstream facilities is not within our control. These pipelines, plants and other midstream facilities may become unavailable because of testing, turnarounds, line repair, maintenance, reduced operating pressure, lack of operating capacity, regulatory requirements and curtailments of receipt or deliveries due to insufficient capacity or because of damage from severe weather conditions or other operational issues. Further, these pipelines and facilities connected to our assets impose product quality specifications. We may be unable to access such facilities or transport product along interconnected pipelines if the volumes we gather or transport do not meet their product quality requirements. In addition, if our costs to access and transport on these third-party pipelines significantly increase, our profitability could be reduced. If any such increase in costs occurs, if any of these pipelines or other midstream facilities become unable to receive, transport or process product, or if the volumes we gather or transport do not meet the product quality requirements of such pipelines or facilities, our operating margin and cash flow could be adversely affected.

Our debt levels could limit our flexibility and adversely affect our financial health or limit our flexibility to obtain financing and to pursue other business opportunities.

We continue to have the ability to incur debt, subject to limitations in our credit facility. Our level of indebtedness could have important consequences to us, including the following:

- our ability to obtain additional financing, if necessary, for working capital, capital expenditures, acquisitions or other purposes may be impaired or such financing may not be available on favorable terms;
- our funds available for operations, future business opportunities and distributions to unitholders will be reduced by that portion of our cash flows required to make interest payments on our debt;
- our debt level will make us more vulnerable to general adverse economic and industry conditions;
- our ability to plan for, or react to, changes in our business and the industry in which we operate; and
- our risk that we may default on our debt obligations.

In addition, our ability to make scheduled payments or to refinance our obligations depends on our successful financial and operating performance, which will be affected by prevailing economic, financial and industry conditions, many of which are beyond our control. If our cash flow and capital resources are insufficient to fund our debt service obligations, we may be forced to take actions such as reducing distributions, reducing or delaying our business activities, acquisitions, investments or capital expenditures, selling assets, restructuring or refinancing our debt or seeking additional equity capital. We may not be able to effect any of these actions on satisfactory terms or at all.

The terms of our credit facility and indentures may restrict our current and future operations, particularly our ability to respond to changes in business or to take certain actions.

Our credit facility agreement and the indentures governing our senior notes contain, and any future indebtedness we incur will likely contain, a number of restrictive covenants that impose significant operating and financial restrictions, including restrictions on our ability to engage in acts that may be in our best long-term interest. One or more of these agreements include covenants that, among other things, restrict our ability to:

- incur subsidiary indebtedness;
- engage in transactions with our affiliates;
- consolidate, merge or sell substantially all of our assets;
- incur liens;
- enter into sale and lease back transactions; and
- change business activities we conduct.

In addition, our credit facility requires us to satisfy and maintain a specified financial ratio. Our ability to meet that financial ratio can be affected by events beyond our control, and we cannot assure you that we will continue to meet that ratio.

Our ability to comply with the covenants and restrictions contained in our credit facility and indentures 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. A breach of any of these covenants could result in an event of default under our credit facility and indentures. Upon the occurrence of such an event of default, all amounts outstanding under the applicable debt agreements could be declared to be immediately due and payable, and all applicable commitments to extend further credit could be terminated. If indebtedness under our credit facility or indentures is accelerated, there can be no assurance that we will have sufficient assets to repay the indebtedness. The operating and financial restrictions and covenants in these debt agreements and any future financing agreements may adversely affect our ability to finance future operations or capital needs or to engage in other business activities.

A default under ENLC's credit facility could have an adverse effect on the price of our common units and could result in a change of control of our general partner.

ENLC has entered into a credit facility that is secured by, among other things, a first priority lien on 88,528,451 of our common units and the 100% membership interest in our general partner indirectly held by ENLC. Although we are not a party to this credit facility, if a default under such credit facility were to occur, the lenders could foreclose on the pledged equity interests. Any such foreclosure on our common units could have an adverse effect on the market price of our common units. In addition, any foreclosure on ENLC's interest in the general partner would allow the new owner of our general partner to replace the board of directors and officers of our general partner with its own designees and to control the decisions taken by the board of directors and officers. Moreover, any change of control of our general partner would permit the lenders under our credit facility to declare all amounts thereunder immediately due and payable, and if any such event occurs, we may be required to refinance our debt on unfavorable terms, which could negatively impact our results of operations and our ability to make distributions to our unitholders.

Increases 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.

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, our unit price is impacted by our level of cash distributions and implied distribution yield. The distribution yield is often used by investors to compare and rank yield-oriented securities for investment decision-making purposes. Therefore, changes in interest rates, either positive or negative, 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 equity or incur debt for acquisitions or other purposes and our ability to make cash distributions at our intended levels or at all.

We are vulnerable to operational, regulatory and other risks due to our significant assets in South Louisiana and the Texas Gulf Coast, including the effects of adverse weather conditions such as hurricanes.

Our operations and revenues could be significantly impacted by conditions in South Louisiana and the Texas Gulf Coast because we have significant assets located in these two areas. Our concentration of activity in Louisiana and the Texas Gulf Coast makes us more vulnerable than many of our competitors to the risks associated with these areas, including:

- adverse weather conditions, including hurricanes and tropical storms;
- delays or decreases in production, the availability of equipment, facilities or services; and
- changes in the regulatory environment.

Because a significant portion of our operations could experience the same condition at the same time, these conditions could have a relatively greater impact on our results of operations than they might have on other midstream companies that have operations in more diversified geographic areas.

Our business is subject to a number of weather-related risks. These weather conditions can cause significant damage and disruption to our operations and adversely impact our financial condition, results of operations or cash flows.

Virtually all of our operations are exposed to potential natural disasters, including hurricanes, tornadoes, storms, floods, fires, severe temperatures and earthquakes. In particular, South Louisiana and the Texas Gulf Coast experience hurricanes and other extreme weather conditions on a frequent basis. The location of our significant assets and concentration of activity in these regions make us particularly vulnerable to weather risks in these areas.

High winds, storm surge, flooding and other natural disasters can cause significant damage and curtail our operations for extended periods during and after such weather conditions, which may result in decreased revenues and otherwise adversely impact our financial condition, results of operations or cash flow. These interruptions could involve significant damage to people, property or the environment, and repair time and costs could be extensive. Any such event that interrupts the revenues generated by our operations, or which causes us to make significant expenditures not covered by insurance, could reduce our cash available for paying distributions to our partners and, accordingly, adversely affect our financial condition and the market price of our securities.

In addition, we rely on the volumes of natural gas, crude oil, condensate and NGLs gathered, processed, fractionated and transported on our assets. These volumes are influenced by the production from the regions that supply our systems. Adverse weather conditions can cause direct or indirect disruptions to the operations of, and otherwise negatively affect, producers, suppliers, customers and other third parties to which our assets are connected, even if our assets are not damaged. As a result, our financial condition, results of operations and cash flows could be adversely affected.

We may also suffer reputational damage as a result of a natural disaster or other similar event. The occurrence of such an event, or a series of such events, especially if one or more of them occurs in a highly populated or sensitive area, could negatively impact public perception of our operations and/or make it more difficult for us to obtain the approvals, permits, licenses, rights-of-way or real property interests we need in order to operate our assets or complete planned growth projects.

A reduction in demand for NGL products by the petrochemical, refining or other industries or by the fuel markets could materially adversely affect our financial condition, results of operations or cash flows.

The NGL products we produce have a variety of applications, including as heating fuels, petrochemical feedstocks and refining blend stocks. A reduction in demand for NGL products, whether because of general or industry specific economic conditions, new government regulations, global competition, reduced demand by consumers for products made with NGL products (for example, reduced petrochemical demand observed due to lower activity in the automobile and construction industries), increased competition from petroleum-based feedstocks due to pricing differences, mild winter weather for some NGL applications or other reasons could result in a decline in the volume of NGL products we handle or reduce the fees we charge for our services. Our NGL products and the demand for these products are affected as follows:

- *Ethane.* Ethane is typically supplied as purity ethane or as part of ethane-propane mix. Ethane is primarily used in the petrochemical industry as feedstock for ethylene, one of the basic building blocks for a wide range of plastics and other chemical products. Although ethane is typically extracted as part of the mixed NGL stream at gas processing plants, if natural gas prices increase significantly in relation to NGL product prices or if the demand for ethylene falls, it may be more profitable for natural gas processors to leave the ethane in the natural gas stream. Such "ethane rejection" reduces the volume of NGLs delivered for fractionation and marketing.

- *Propane.* Propane is used as a petrochemical feedstock in the production of ethylene and propylene, as a heating, engine and industrial fuel, and in agricultural applications such as crop drying. Changes in demand for ethylene and propylene could adversely affect demand for propane. The demand for propane as a heating fuel is significantly affected by weather conditions. The volume of propane sold is at its highest during the six-month peak heating season of October through March. Demand for our propane may be reduced during periods of warmer-than-normal weather.

- *Normal Butane.* Normal butane is used in the production of isobutane, as a refined product blending component, as a fuel gas, and in the production of ethylene and propylene. Changes in the composition of refined products resulting from governmental regulation, changes in feedstocks, products and economics, demand for heating fuel and for ethylene and propylene could adversely affect demand for normal butane.

- *Isobutane.* Isobutane is predominantly used in refineries to produce alkylates to enhance octane levels. Accordingly, any action that reduces demand for motor gasoline or demand for isobutane to produce alkylates for octane enhancement might reduce demand for isobutane.

- *Natural Gasoline.* Natural gasoline is used as a blending component for certain refined products and as a feedstock used in the production of ethylene and propylene. Changes in the mandated composition resulting from governmental regulation of motor gasoline and in demand for ethylene and propylene could adversely affect demand for natural gasoline.

NGLs and products produced from NGLs are sold in competitive global markets. Any reduced demand for ethane, propane, normal butane, isobutane or natural gasoline in the markets we access for any of the reasons stated above could adversely affect demand for the services we provide as well as NGL prices, which would negatively impact our financial condition, results of operations or cash flows.

We expect to encounter significant competition in any new geographic areas into which we seek to expand, and our ability to enter such markets may be limited.

If we expand our operations into new geographic areas, we expect to encounter significant competition for natural gas, condensate, NGLs and crude oil supplies and markets. Competitors in these new markets will include companies larger than us, which have both lower cost of capital and greater geographic coverage, as well as smaller companies, which have lower total cost structures. As a result, we may not be able to successfully develop greenfield or acquire assets located in new geographic areas and our results of operations could be adversely affected.

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

We do not own most of the land on which our pipelines, compression and plant facilities are located, 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 leases or if such rights-of-way or leases lapse or terminate. We sometimes obtain the rights to land owned by third parties and governmental agencies for a specific period of time. Our loss of these rights, through our inability to renew right-of-way contracts, leases or otherwise, could cause us to cease operations on the affected land, increase costs related to continuing operations elsewhere and reduce our revenue.

We offer pipeline, truck, rail and barge services. Significant delays, inclement weather or increased costs affecting these transportation methods could materially affect our results of operations.

We offer pipeline, truck, rail and barge services. The costs of conducting these services could be negatively affected by factors outside of our control, including rail service interruptions, new laws and regulations, rate increases, tariffs, rising fuel costs or capacity constraints. Inclement weather, including hurricanes, tornadoes, snow, ice and other weather events, can negatively impact our distribution network. In addition, rail, truck or barge accidents involving the transportation of hazardous materials could result in significant environmental penalties and remediation, claims arising from personal injury and property damage.

We could experience increased severity or frequency of trucking accidents and other claims, which could materially affect our results of operations.

Potential liability associated with accidents in the trucking industry is severe and occurrences are unpredictable. A material increase in the frequency or severity of accidents or workers' compensation claims or the unfavorable development of existing claims could materially adversely affect our results of operations. In the event that accidents occur, we may be unable to obtain desired contractual indemnities, and our insurance may be inadequate in certain cases. The occurrence of an event not fully insured or indemnified against, or the failure or inability of a customer or insurer to meet its indemnification or insurance obligations, could result in substantial losses.

Changes in trucking regulations may increase our costs and negatively impact our results of operations.

Our trucking services are subject to regulation as motor carriers by the DOT and by various state agencies, whose regulations include certain permit requirements of state highway and safety authorities. These regulatory authorities exercise broad powers over our trucking operations, generally governing such matters as the authorization to engage in motor carrier operations, safety, equipment testing and specifications and insurance requirements. There are additional regulations specifically relating to the trucking industry, including testing and specification of equipment and product handling requirements. The trucking industry is subject to possible regulatory and legislative changes that may impact our operations and affect the economics of the industry by requiring changes in operating practices or by changing the demand for or the cost of providing trucking services. Some of these possible changes include increasingly stringent fuel emission limits, changes in the regulations that govern the amount of time a driver may drive or work in any specific period, limits on vehicle weight and size and other matters, including safety requirements.

If we do not make acquisitions on economically acceptable terms or efficiently and effectively integrate the acquired assets with our asset base, our future growth will be limited.

Our ability to grow depends, in part, on our ability to make acquisitions that result in an increase in cash generated from operations on a per unit basis. If we are unable to make accretive acquisitions either because we are (1) unable to identify attractive acquisition candidates or negotiate acceptable purchase contracts with them, (2) unable to obtain financing for these acquisitions on economically acceptable terms or at all or (3) outbid by competitors, then our future growth and our ability to increase distributions will be limited.

From time to time, we may evaluate and seek to acquire assets or businesses that we believe complement our existing business and related assets. We may acquire assets or businesses that we plan to use in a manner materially different from their prior owner's use. Any acquisition involves potential risks, including:

- the inability to integrate the operations of recently acquired businesses or assets, especially if the assets acquired are in a new business segment or geographic area;
- the diversion of management's attention from other business concerns;
- the failure to realize expected volumes, revenues, profitability or growth;
- the failure to realize any expected synergies and cost savings;
- the coordination of geographically disparate organizations, systems and facilities;
- the assumption of unknown liabilities;
- the loss of customers or key employees from the acquired businesses;
- a significant increase in our indebtedness; and
- potential environmental or regulatory liabilities and title problems.

Management's assessment of these risks is inexact and may not reveal or resolve all existing or potential problems associated with an acquisition. Realization of any of these risks could adversely affect our operations and cash flows. If we consummate any future acquisition, our capitalization and results of operations may change significantly, and you will not have the opportunity to evaluate the economic, financial and other relevant information that we will consider in determining the application of these funds and other resources.

We may not be able to retain existing customers or acquire new customers, which would reduce our revenues and limit our future profitability.

The renewal or replacement of existing contracts with our customers at rates sufficient to maintain current revenues and cash flows depends on a number of factors beyond our control, including the price of, and demand for, crude oil, condensate, NGLs and natural gas in the markets we serve and competition from other midstream service providers. Our competitors include companies larger than we are, which could have both a lower cost of capital and a greater geographic coverage, as well as companies smaller than we are, which could have lower total cost structures. In addition, competition is increasing in some markets that have been overbuilt, resulting in an excess of midstream energy infrastructure capacity, or where new market entrants are willing to provide services at a discount in order to establish relationships and gain a foothold. The inability of our management to renew or replace our current contracts as they expire and to respond appropriately to changing market conditions could have a negative effect on our profitability.

In particular, our ability to renew or replace our existing contracts with industrial end-users and utilities impacts our profitability. For the year ended December 31, 2017, approximately 53.9% of our sales of gas transported using our physical facilities were to industrial end-users and utilities. As a consequence of the increase in competition in the industry and volatility of natural gas prices, industrial end-users and utilities may be reluctant to enter into long-term purchase contracts. Many industrial end-users purchase natural gas from more than one natural gas company and have the ability to change providers at any time. Some of these industrial end-users also have the ability to switch between gas and alternate fuels in response to relative price fluctuations in the market. Because there are numerous companies of greatly varying size and financial capacity that compete with us in marketing natural gas, we often compete in the industrial end-user and utilities markets primarily on the basis of price.

We are exposed to the credit risk of our customers and counterparties, and a general increase in the nonpayment and nonperformance by our customers could have an adverse effect on our financial condition, results of operations or cash flows.

Risks of nonpayment and nonperformance by our customers are a major concern in our business. We are subject to risks of loss resulting from nonpayment or nonperformance by our customers and other counterparties, such as our lenders and hedging counterparties. Any increase in the nonpayment and nonperformance by our customers could adversely affect our results of operations and reduce our ability to make distributions to our unitholders. Additionally, equity values for many of our customers continue to be low. The combination of a reduction in cash flow from lower commodity prices, a reduction in borrowing bases under reserve-based credit facilities and the lack of availability of debt or equity financing may result in a significant reduction in our customers' liquidity and 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.

Increased federal, state and local legislation and regulatory initiatives, as well as government reviews relating to hydraulic fracturing could result in increased costs and reductions or delays in natural gas production by our customers, which could adversely impact our revenues.

A portion of our suppliers' and customers' natural gas production is developed from unconventional sources, such as deep gas shales, that require hydraulic fracturing as part of the completion process. State legislatures and agencies have enacted legislation and promulgated rules to regulate hydraulic fracturing, require disclosure of hydraulic fracturing chemicals, temporarily or permanently ban hydraulic fracturing and impose additional permit requirements and operational restrictions in certain jurisdictions or in environmentally sensitive areas. EPA and the BLM have also issued rules, conducted studies and made proposals that, if implemented, could either restrict the practice of hydraulic fracturing or subject the process to further regulation. For instance, the EPA has issued final regulations under the federal Clean Air Act establishing performance standards, including standards for the capture of air emissions released during hydraulic fracturing, and adopted rules prohibiting the discharge of wastewater from hydraulic fracturing operations to publicly owned wastewater treatment plants. Although the EPA has announced its intention to reconsider the regulations relating to the capture of air emissions in April 2017 and has sought to stay its requirements, the rule remains in effect along with the restriction on discharges to publicly owned wastewater treatment plants. The BLM also adopted new rules, effective on January 17, 2017, to reduce venting, flaring and leaks during oil and natural gas production activities on onshore federal and Indian leases. Certain provisions of the BLM rule went into effect in January 2017, while others were scheduled to go into effect in January 2018. In December 2017, BLM published a final rule delaying the 2018 provisions until 2019. State and federal regulatory agencies also have recently focused on a possible connection between the operation of injection wells used for oil and gas waste waters and an observed increase in induced seismicity, which has resulted in some regulation at the state level. For instance, in December 2016 the Oklahoma Corporation Commission released well completion seismicity guidelines for operators in the STACK play that call for hydraulic fracturing operations to be suspended following earthquakes of certain magnitudes in the vicinity. As regulatory agencies continue to study induced seismicity, additional legislative and regulatory initiatives could affect our customers' injection well operations as well as our brine disposal operations.

We cannot predict whether any additional legislation or regulations will be enacted and, if so, what the provisions would be. If additional levels of regulation and permits were required through the adoption of new laws and regulations at the federal or state level, that could lead to delays, increased operating costs and process prohibitions for our suppliers and customers that could reduce the volumes of natural gas that move through our gathering systems which could materially adversely affect our revenue and results of operations.

Transportation on certain of our natural gas pipelines is subject to federal and state rate and service regulation, which could limit the revenues we collect from our customers and adversely affect the cash available for distribution to our unitholders. The imposition of regulation on our currently unregulated natural gas pipelines also could increase our operating costs and adversely affect the cash available for distribution to our unitholders.

The rates, terms and conditions of service under which we transport natural gas in our pipeline systems in interstate commerce are subject to regulation by FERC under the NGA and Section 311 of the NGPA and the rules and regulations promulgated under those statutes. Under the NGA, FERC regulation requires that interstate natural gas pipeline rates be filed with FERC and that these rates be "just and reasonable," not unduly preferential and not unduly discriminatory, although negotiated or settlement rates may be accepted in certain circumstances. Interested persons may challenge proposed new or changed rates, and FERC is authorized to suspend the effectiveness of such rates pending an investigation or hearing. FERC may also investigate, upon complaint or on its own motion, rates that are already in effect and may order a pipeline to change its rates prospectively. Accordingly, action by FERC could adversely affect our ability to establish rates that cover operating costs and allow for a reasonable return. An adverse determination in any future rate proceeding brought by or against us could have a material adverse effect on our business, financial condition, results of operations, and cash available for distribution. Under the NGPA, we are required to justify our rates for interstate transportation service on a cost-of-service basis every five years. In addition, our intrastate natural gas pipeline operations are subject to regulation by various agencies of the states in which they are located. Should FERC or any of these state agencies determine that our rates for transportation service should be lowered, our business could be adversely affected.

The rates charged by our natural gas pipelines may also be affected by the ongoing uncertainty regarding FERC's income tax allowance policy as a result of ongoing proceedings at FERC related to third parties or general FERC policies. The ultimate outcome of these proceedings, which may not be definitively resolved for some time, is not certain and could result in changes to FERC's general treatment of income tax allowances in the cost of service or to the discounted cash flow return on equity. Additionally, recently enacted legislation commonly referred to as the Tax Cuts and Jobs Act (the "Tax Cuts and Jobs Act") includes a reduction in the highest marginal U.S. federal corporate income tax rate from 35% to 21%, effective for taxable years beginning on or after January 1, 2018. At this time, it is uncertain how and when FERC will require this reduction in corporate tax rates to be reflected in the income tax allowance of regulated entities for rate-making purposes. Depending upon the resolution of these issues, the cost of service rates of our interstate natural gas pipelines could be affected to the extent FERC proposes new rates or changes to our existing rates or if our rates are subject to compliance or challenged by FERC.

Our natural gas gathering and processing activities generally are exempt from FERC regulation under the Natural Gas Act. However, the distinction between FERC-regulated transmission services and federally unregulated gathering services is the subject of substantial, ongoing litigation, so the classification and regulation of our gathering facilities are subject to change based on future determinations by FERC and the courts. Natural gas gathering may receive greater regulatory scrutiny at both the state and federal levels since FERC has less extensively regulated the gathering activities of interstate pipeline transmission companies and a number of such companies have transferred gathering facilities to unregulated affiliates. Application of FERC jurisdiction to our gathering facilities could increase our operating costs, decrease our rates and adversely affect our business. Our gathering operations also may be or become subject to safety and operational regulations relating to the design, installation, testing, construction, operation, replacement and management 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 our operations, but the industry could be required to incur additional capital expenditures and increased costs depending on future legislative and regulatory changes.

If we fail to comply with all the applicable FERC-administered statutes, rules, regulations and orders, we could be subject to substantial penalties and fines. Under the EPAct 2005, FERC has civil penalty authority to impose penalties for current violations of the NGA or NGPA of up to $1.0 million per day for each violation. The maximum penalty authority established by statute has been adjusted to $1.2 million and will continue to be adjusted periodically for inflation. FERC also has the power to order disgorgement of profits from transactions deemed to violate the NGA and EPAct 2005.

Other state and local regulations also affect our business. We are subject to some ratable take and common purchaser statutes in the states where we operate. 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 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. Federal law leaves any economic regulation of natural gas gathering to the states, and some of the states in which we operate have adopted complaint-based or other limited economic regulation of natural gas gathering activities. States in which we operate that have adopted some form of complaint-based regulation, like Texas, generally allow natural gas producers and shippers to file complaints with state regulators in an effort to resolve grievances relating to natural gas gathering access and rate discrimination.

Transportation on our liquids pipelines is subject to federal and state rate and service regulation, which could limit the revenues we collect from our customers and adversely affect the cash available for distribution to our unitholders. The imposition of regulation on our currently unregulated liquids pipeline operations also could increase our operating costs and adversely affect the cash available for distribution to our unitholders.

Our interstate liquids transportation pipelines are subject to regulation by FERC under the ICA, the Energy Policy Act of 1992 and the rules and regulations promulgated under those laws. If, upon completion of an investigation, FERC finds that new or changed rates are unlawful, it is authorized to require the pipeline to refund revenues collected in excess of the just and reasonable rates during the term of the investigation. FERC may also investigate, upon complaint or on its own motion, rates that are already in effect and may order a carrier to change its rates prospectively if it determines that the rates are unjust and unreasonable or unduly discriminatory or preferential. Under certain circumstances, FERC could limit our recovery of costs or could require us to reduce our rates and the payment of reparations to complaining shippers for up to two years prior to the date of the complaint. In particular, ongoing uncertainty surrounding FERC's current income tax allowance policy could affect our rates going forward, as could proposed changes to FERC's annual indexing methodology, including adoption of a policy that would deny proposed index increases for pipelines under certain circumstances where revenues exceed cost-of-service numbers by a certain percentage or where the proposed index increases exceed certain annual cost changes, all of which could have a material impact on our business. Such changes, if accepted, could decrease our rates and adversely affect our business.

As we acquire, construct and operate new liquids assets and expand our liquids transportation business, the classification and regulation of our liquids transportation services, including services that our marketing companies provide on our FERC-regulated liquids pipelines, are subject to ongoing assessment and change based on the services we provide and determinations by FERC and the courts. Such changes may subject additional services we provide to regulation by FERC, which could increase our operating costs, decrease our rates and adversely affect our business.

We may incur significant costs and liabilities resulting from compliance with pipeline safety regulations.

The pipelines we own and operate are subject to stringent and complex regulation related to pipeline safety and integrity management. For instance, the Department of Transportation, through PHMSA, has established a series of rules that require pipeline operators to develop and implement integrity management programs for hazardous liquid (including oil) pipeline segments that, in the event of a leak or rupture, could affect HCAs. PHMSA also recently proposed rules that would expand existing integrity management requirements to natural gas transmission and gathering lines in areas with medium population densities. Additional action by PHMSA with respect to pipeline integrity management requirements may occur in the future. At this time, we cannot predict the cost of such requirements, but they could be significant. Moreover, violations of pipeline safety regulations can result in the imposition of significant penalties.

Several states have also passed legislation or promulgated rules to address pipeline safety. Compliance with pipeline integrity laws and other pipeline safety regulations issued by state agencies such as the TRRC could result in substantial expenditures for testing, repairs and replacement. For example, TRRC regulations require periodic testing of all intrastate pipelines meeting certain size and location requirements. Our costs relating to compliance with the required testing under the TRRC regulations were approximately $2.3 million, $3.3 million and $3.3 million for the years ended December 31, 2017, 2016 and 2015, respectively. If our pipelines fail to meet the safety standards mandated by the TRRC or PHMSA regulations, then we may be required to repair or replace sections of such pipelines or operate the pipelines at a reduced operating pressure, the cost of which actions cannot be estimated at this time.

Due to the possibility of new or amended laws and regulations or reinterpretation of existing laws and regulations, there can be no assurance that future compliance with PHMSA or state requirements will not have a material adverse effect on our results of operations or financial positions. Moreover, because certain of our operations are located around urban or more populated areas, such as the Barnett Shale, we may incur additional expenses from compliance with municipal and other local or state regulations that impose various obligations including, among other things, regulating the locations of our facilities; limiting the noise, odor, or light levels of our facilities; and requiring certain other improvements, including to the appearance of our facilities, that result in increased costs for our facilities. We are also subject to claims by neighboring landowners for nuisance related to the construction and operation of our facilities, which could subject us to damages for declines in neighboring property values due to our construction and operation activities.

Failure to comply with existing or new environmental laws or regulations or an accidental release of hazardous substances, hydrocarbons or wastes into the environment may cause us to incur significant costs and liabilities.

Many of the operations and activities of our pipelines, gathering systems, processing plants, fractionators, brine disposal operations and other facilities are subject to significant federal, state and local environmental laws and regulations, the violation of which can result in administrative, civil and criminal penalties, including civil fines, injunctions or both. The obligations imposed by these laws and regulations include obligations related to air emissions and discharge of pollutants from our pipelines and other facilities and the cleanup of hazardous substances and other wastes that are or may have been released at properties currently or previously owned or operated by us or locations to which we have sent wastes for treatment or disposal. These laws impose strict, joint and several liability for the remediation of contaminated areas. Private parties, including the owners of properties near our facilities or upon or through which our gathering systems traverse, may also have the right to pursue legal actions to enforce compliance and to seek damages for non-compliance with environmental laws for releases of contaminants or for personal injury or property damage.

Our business may be adversely affected by increased costs due to stricter pollution control requirements or liabilities resulting from non-compliance with required operating or other regulatory permits. New environmental laws or regulations, including, for example, legislation relating to the control of greenhouse gas emissions, or changes in existing environmental laws or regulations might adversely affect our products and activities, including processing, storage and transportation, as well as waste management and air emissions. Federal and state agencies could also impose additional safety requirements, any of which could affect our profitability. Changes in laws or regulations could also limit our production or the operation of our assets or adversely affect our ability to comply with applicable legal requirements or the demand for crude oil, brine disposal services or natural gas, which could adversely affect our business and our profitability.

Recent rules under the Clean Air Act imposing more stringent requirements on the oil and gas industry could cause our customers and us to incur increased capital expenditures and operating costs as well as reduce the demand for our services.

We are subject to stringent and complex regulation under the federal Clean Air Act, implementing regulations, and state and local equivalents, including regulations related to controls for oil and natural gas production, pipelines, and processing operations. For instance, the EPA finalized new rules, effective August 2, 2016, to regulate emissions of methane and volatile organic compounds from new and modified sources in the oil and gas sector. The EPA announced its intention to reconsider those regulations in April 2017 and has sought to stay its requirements. However, the rule remains in effect. The EPA also finalized a rule regarding the alternative criteria for aggregating multiple small surface sites into a single source for air quality permitting purposes. This rule could cause small facilities, on an aggregate basis, to be deemed a major source if within one quarter-mile of one another, thereby triggering more stringent air permitting processes and requirements across the oil and gas industry. In addition, on November 10, 2016, the EPA issued a final Information Collection Request (“ICR”) that requires numerous oil and gas companies to provide information regarding methane emissions from existing oil and gas facilities, a step used to provide a basis for future rulemaking. The EPA withdrew this ICR in March of 2017. The BLM also adopted new rules on November 15, 2016, effective January 17, 2017, to reduce venting, flaring, and leaks during oil and natural gas production activities on onshore federal and Indian leases. Certain provisions of the BLM rule went into effect in January 2017, while others were scheduled to go into effect in January 2018. In December 2017, BLM published a final rule delaying the 2018 provisions until 2019.

Additional regulation of GHG emissions from the oil and gas industry remains a possibility. These regulations could require a number of modifications to our operations, and our natural gas exploration and production suppliers’ and customers’ operations, including the installation of new equipment, which could result in significant costs, including increased capital expenditures and operating costs. The incurrence of such expenditures and costs by our suppliers and customers could result in reduced production by those suppliers and customers and thus translate into reduced demand for our services. Responding to rule challenges, the EPA has since revised certain aspects of its April 2012 rules and has indicated that it may reconsider other aspects of the rules.

Climate change legislation and regulatory initiatives could result in increased operating costs and reduced demand for the natural gas and NGL services we provide.

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. In addition, 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 adoption of the Paris Agreement. The Paris Agreement became effective November 4, 2016 and requires 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. Although the Trump Administration has announced its intent to withdraw from the Paris Agreement, the earliest effective date of this withdrawal pursuant to the terms of the Paris Agreement is November 2020. At the federal regulatory level, both the EPA and the BLM have adopted regulations for the control of methane emissions, which also include leak detection and repair requirements, from the oil and gas industry.

In addition, many states have already taken legal measures to reduce emissions of GHGs, primarily through the planned development of GHG emission inventories and/or regional GHG cap and trade programs. Most of these cap and trade programs work by requiring either major sources of emissions, such as electric power plants, or major producers of fuels, such as refineries and NGL fractionation plants, to acquire and surrender emission allowances with the number of allowances available for purchase reduced each year until the overall GHG emission reduction goal is achieved.

Although it is not possible at this time to predict whether future legislation or new regulations may be adopted to address greenhouse gas emissions or how such measures would impact our business, the adoption of legislation or regulations imposing reporting or permitting obligations on, or limiting emissions of GHGs from, our equipment and operations could require us to incur additional costs to reduce emissions of GHGs associated with our operations, could adversely affect our performance of operations in the absence of any permits that may be required to regulate emission of GHGs or could adversely affect demand for the natural gas we gather, process or otherwise handle in connection with our services.

The ESA and MBTA govern our operations and additional restrictions may be imposed in the future, which could have an adverse impact on our operations.

The ESA and analogous state laws restrict activities that may affect endangered or threatened species or their habitats. Similar protections are offered to migratory birds under the MBTA. The U.S. Fish and Wildlife Service and state agencies may designate critical or suitable habitat areas that they believe are necessary for the survival of threatened or endangered species, which could materially restrict use of or access to federal, state and private lands. Some of our operations may be located in areas that are designated as habitats for endangered or threatened species or that may attract migratory birds. In these areas, we may be obligated to develop and implement plans to avoid potential adverse impacts to protected species, and we may be prohibited from conducting operations in certain locations or during certain seasons, such as breeding and nesting seasons, when our operations could have an adverse effect on the species. It is also possible that a federal or state agency could order a complete halt to our activities in certain locations if it is determined that such activities may have a serious adverse effect on a protected species. In addition, the U.S. Fish and Wildlife Service and state agencies regularly review species that are listing candidates, and designations of additional endangered or threatened species, or critical or suitable habitat, under the ESA could cause us to incur additional costs or become subject to operating restrictions or bans in the affected areas.

Our business involves many hazards and operational risks, some of which may not be fully covered by insurance. The occurrence of a significant accident or other event that is not fully insured could adversely affect our operations and financial condition.

Our operations are subject to the many hazards inherent in the gathering, compressing, processing, transporting, fractionating, disposing and storage of natural gas, NGLs, condensate, crude oil and brine, including:

- damage to pipelines, facilities, storage caverns, equipment and surrounding properties caused by hurricanes, floods, sink holes, fires and other natural disasters and acts of terrorism;
- inadvertent damage to our assets from construction or farm equipment;
- leaks of natural gas, NGLs, crude oil, condensate and other hydrocarbons;
- induced seismicity;
- rail accidents, barge accidents and truck accidents;
- equipment failure; and

- fires and explosions.

These risks could result in substantial losses due to personal injury and/or loss of life, severe damage to and destruction of property and equipment and pollution or other environmental damage and may result in curtailment or suspension of our related operations. We are not fully insured against all risks incident to our business. In accordance with typical industry practice, we have appropriate levels of business interruption and property insurance on our underground pipeline systems. We are not insured against all environmental accidents that might occur. If a significant accident or event occurs that is not fully insured, it could adversely affect our operations and financial condition.

The adoption of derivatives legislation by the United States Congress and promulgation of related regulations could have an adverse effect on our ability to hedge risks associated with our business.

Comprehensive financial reform legislation was signed into law by the President on July 21, 2010. The legislation calls for the Commodities Futures Trading Commission (“CFTC”) to regulate certain markets for derivative products, including over-the-counter (“OTC”) derivatives. The CFTC has issued several new relevant regulations and other rulemakings are pending at the CFTC, the product of which would be rules that implement the mandates in the new legislation to cause significant portions of derivatives markets to clear through clearinghouses. While some of these rules have been finalized, some have not and, as a result, the final form and timing of the implementation of the new regulatory regime affecting commodity derivatives remains uncertain.

In particular, on October 18, 2011, the CFTC adopted final rules under the Dodd-Frank Act establishing position limits for certain energy commodity futures and options contracts and economically equivalent swaps, futures and options. The position limit levels set the maximum amount of covered contracts that a trader may own or control separately or in combination, net long or short. The final rules also contained limited exemptions from position limits which would be phased in over time for certain bona fide hedging transactions and positions. The CFTC’s original position limits rule was challenged in court by two industry associations and was vacated and remanded by a federal district court. However, the CFTC proposed and revised new rules in November 2013 and December 2016, respectively, that would place limits on positions in certain core futures and equivalent swaps contracts for or linked to certain physical commodities, subject to exceptions for certain bona fide hedging transactions. The CFTC has sought comment on the position limits rule as reproposed, but these new position limit rules are not yet final and the impact of those provisions on us is uncertain at this time. The CFTC has withdrawn its appeal of the court order vacating the original position limits rule.

The legislation and new regulations may also require counterparties to our derivative instruments to spin off some of their derivatives activities to separate entities, which may not be as creditworthy as the current counterparties. The new legislation and any new regulations could significantly increase the cost of derivative contracts, materially alter the terms of derivative contracts, reduce the availability of derivatives to protect against risks we encounter, reduce our ability to monetize or restructure our existing derivative contracts, and increase our exposure to less creditworthy counterparties. If we reduce our use of derivatives 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 to generate sufficient cash flow to pay quarterly distributions at current levels or at all. Our revenues could be adversely affected if a consequence of the legislation and regulations is to lower commodity prices. Any of these consequences could have a material, adverse effect on us, our financial condition and our results of operations.

Our use of derivative financial instruments does not eliminate our exposure to fluctuations in commodity prices and interest rates and has in the past and could in the future result in financial losses or reduce our income.

Our operations expose us to fluctuations in commodity prices, and our credit facility exposes us to fluctuations in interest rates. We use over-the-counter price and basis swaps with other natural gas merchants and financial institutions. Use of these instruments is intended to reduce our exposure to short-term volatility in commodity prices. As of December 31, 2017, we have hedged only portions of our expected exposures to commodity price risk. In addition, to the extent we hedge our commodity price risk using swap instruments, we will forego the benefits of favorable changes in commodity prices. Although we do not currently have any financial instruments to eliminate our exposure to interest rate fluctuations, we may use financial instruments in the future to offset our exposure to interest rate fluctuations.

Even though monitored by management, our hedging activities may fail to protect us and could reduce our earnings and cash flow. Our hedging activity may be ineffective or adversely affect cash flow and earnings because, among other factors:

- hedging can be expensive, particularly during periods of volatile prices;

- our counterparty in the hedging transaction may default on its obligation to pay or otherwise fail to perform; and
- available hedges may not correspond directly with the risks against which we seek protection. For example:
  - the duration of a hedge may not match the duration of the risk against which we seek protection;
  - variations in the index we use to price a commodity hedge may not adequately correlate with variations in the index we use to sell the physical commodity (known as basis risk); and
  - we may not produce or process sufficient volumes to cover swap arrangements we enter into for a given period. If our actual volumes are lower than the volumes we estimated when entering into a swap for the period, we might be forced to satisfy all or a portion of our derivative obligation without the benefit of cash flow from our sale or purchase of the underlying physical commodity, which could adversely affect our liquidity.

A failure in our computer systems or a terrorist or cyber-attack on us, or third parties with whom we have a relationship, may adversely affect our ability to operate our business.

We are reliant on technology to conduct our business. Our business is dependent upon our operational and financial computer systems to process the data necessary to conduct almost all aspects of our business, including operating our pipelines, truck fleet and storage facilities, recording and reporting commercial and financial transactions and receiving and making payments. Any failure of our computer systems, or those of our customers, suppliers or others with whom we do business, could materially disrupt our ability to operate our business. Unknown entities or groups have mounted so-called “cyber-attacks” on businesses to disable or disrupt computer systems, disrupt operations and steal funds or data. 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. In addition, our 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 business and results of operations. Strategic targets, such as energy-related assets, may be at greater risk of future terrorist or cyber-attacks than other targets in the United States. Our insurance may not protect us against such occurrences. Any such terrorist or cyber-attack that affects us or our customers, suppliers or others with whom we do business, could have a material adverse effect on our business, cause us to incur a material financial loss, subject us to possible legal claims and liability and/or damage our reputation.

Moreover, as the sophistication of cyber attacks continues to evolve, we may be required to expend significant additional resources to further enhance our digital security or to remediate vulnerabilities. In addition, cyber-attacks against us or others in our industry could result in additional regulations, which could lead to increased regulatory compliance costs, insurance coverage cost or capital expenditures. We cannot predict the potential impact to our business or the energy industry resulting from additional regulations.

Our success depends on key members of our management, the loss or replacement of whom could disrupt our business operations.

We depend on the continued employment and performance of the officers of our general partner and key operational personnel. If any of these officers or other key personnel resign or become unable to continue in their present roles and are not adequately replaced, our business operations could be materially adversely affected. We do not maintain any “key man” life insurance for any officers.

Failure to attract and retain an appropriately qualified workforce could reduce labor productivity and increase labor costs, which could have a material adverse effect on our business and results of operations.

Gathering and compression services require laborers skilled in multiple disciplines, such as equipment operators, mechanics and engineers, among others. 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.

Subsidence and coastal erosion could damage our pipelines along the Gulf Coast and offshore and the facilities of our customers, which could adversely affect our operations and financial condition.

Our pipeline operations along the Gulf Coast and offshore could be impacted by subsidence and coastal erosion. Such processes could cause serious damage to our pipelines, which could affect our ability to provide transportation services. Additionally, such processes could impact our customers who operate along the Gulf Coast, and they may be unable to utilize our services. Subsidence and coastal erosion could also expose our operations to increased risks associated with severe weather conditions, such as hurricanes, flooding and rising sea levels. As a result, we may incur significant costs to repair and preserve our pipeline infrastructure. Such costs could adversely affect our financial condition, results of operation or cash flows.

Our assets were constructed over many decades using varying construction and coating techniques, which may cause our inspection, maintenance or repair costs to increase in the future. In addition, there could be service interruptions due to unknown events or conditions or increased downtime associated with our pipelines that could have a material adverse effect on our financial condition, results of operations or cash flows.

Our pipelines were constructed over many decades. Pipelines are generally long-lived assets, and pipeline construction and coating techniques have varied over time and can vary for individual pipelines. Depending on the construction era and quality, some assets will require more frequent inspections or repairs, which could result in increased maintenance or repair expenditures in the future. Any significant increase in these expenditures could adversely affect our financial condition, results of operations or cash flows.

Risk Inherent in an Investment in the Partnership

Cash distributions are not guaranteed and may fluctuate with our performance and the establishment of financial reserves.

Because distributions on our units are dependent on the amount of cash we generate, distributions may fluctuate based on our performance. The actual amount of cash that is available to be distributed each quarter will depend on numerous factors, some of which are beyond our control and the control of our general partner. Cash distributions are dependent primarily on cash flow, including cash flow from financial reserves and working capital borrowings, and not solely on profitability, which is affected by non-cash items. Therefore, cash distributions might be made during periods when we record losses and might not be made during periods when we record profits.

We may not have sufficient available cash from operating surplus each quarter to enable us to make cash distributions at our current distribution rate under our cash distribution policy. 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 we charge and the margins we realize for our services;
- the prices of, levels of production of and demand for crude oil, natural gas, condensate and NGLs;
- the volume of natural gas we gather, compress, process, transport and sell, the volume of NGLs we process or fractionate and sell, the volume of crude oil we handle at our crude terminals, the volume of crude oil we gather, transport, purchase and sell, the volume of condensate we stabilize and transport and the volumes of brine we dispose;
- the relationship between natural gas and NGL prices;
- cash settlements of hedging positions;
- the level of competition from other midstream energy companies;
- the level of our operating and maintenance 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, some of which are beyond our control, including:

- the level of capital expenditures we make;
- our ability to make borrowings under our credit facility to pay distributions;
- the cost of acquisitions;
- our debt service requirements and other liabilities;

- fluctuations in our working capital needs;
- general and administrative expenses;
- restrictions on distributions contained in our debt agreements; and
- the amount of cash reserves established by our general partner for the proper conduct of our business.

Because of these factors, we may not be able, or may not have sufficient available cash to pay distributions to unitholders each quarter. Furthermore, you should also be aware that the amount of cash we have available for distribution depends primarily upon our cash flows, including cash flow from financial reserves and borrowings under our credit facility, and is not solely a function of profitability, which will be affected by non-cash items. As a result, we may make cash distributions during periods when we record losses and may not make cash distributions during periods when we record net income.

Devon, through its control of ENLC, controls our general partner, which has sole responsibility for conducting our business and managing our operations. Devon, ENLC and our general partner have conflicts of interest with, and may favor Devon's interests to the detriment of, our unitholders.

Devon, through its control of ENLC, controls our general partner and indirectly has the power to appoint all of the officers and directors of our general partner. Although our general partner has a fiduciary 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 its owner, ENLC, in which Devon owns the manager and a 64.0% limited liability company interest as of December 31, 2017. Conflicts of interest may arise in the future among Devon, ENLC and its affiliates, including our general partner, on the one hand, and our partnership and our unitholders, on the other hand. As a result of these conflicts, our general partner may favor its own interests and those of its affiliates, including Devon and ENLC, over our interests. These conflicts include, among others, the following situations:

Conflicts Relating to Control

- our partnership agreement limits our general partner's liability and reduces its fiduciary duties, while also restricting the remedies available to our unitholders for actions that might, without these limitations, constitute breaches of fiduciary duty by our general partner;
- in resolving conflicts of interest, our general partner is allowed to take into account the interests of parties in addition to unitholders, which has the effect of limiting its fiduciary duties to the unitholders;
- our general partner's affiliates may engage in limited competition with us;

Conflicts Relating to Costs

- our general partner determines the amount and timing of asset purchases and sales, capital expenditures, borrowings, issuance of additional limited partner interests and reserves;
- our general partner determines which costs incurred by it and its affiliates are reimbursable by us; and
- our general partner is not restricted from causing us to pay it or its affiliates for any services rendered on terms that are fair and reasonable to us or entering into additional contractual arrangements with any of these entities on our behalf.

Our unitholders will have limited voting rights and will not be entitled to elect our general partner or the board of directors of our general partner, which could reduce the price at which our common units will trade.

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 did not elect our general partner or the board of directors of our general partner and have no right to elect our general partner or the board of directors of our general partner on an annual or other continuing basis. The board of directors of our general partner, including its independent directors, is chosen indirectly by ENLC, subject, in certain circumstances, to the designation rights of certain of our investors with respect to one director. In addition, the partnership agreement 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. As a result of these limitations, the price at which our common units trade could be diminished because of the absence or reduction of a takeover premium in the trading price.

Even if our unitholders are dissatisfied with the performance of our general partner, they have little ability to remove our general partner.

Our unitholders have little ability to remove our general partner because the general partner and its affiliates own a significant amount of our outstanding units. The vote of the holders of at least 66 2/3% of all outstanding common units voting together as a single class is required to remove the general partner. Affiliates of the general partner controlled approximately 52.3% of all the outstanding units as of February 14, 2018.

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

Unitholders' voting rights are further restricted by the partnership agreement, which provides that any units held by a person that owns 20.0% 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 of the general partner, cannot be voted on any matter.

Cost reimbursements due to our general partner and its affiliates for services provided, which will be determined by our general partner, could be substantial and would reduce the cash available for distribution to our unitholders.

Prior to making any distributions on the units, we reimburse our general partner and its affiliates, including officers and directors of our general partner, for all expenses they incur on our behalf. These expenses will include all costs incurred by our general partner and its affiliates in the discharge of their duties to our partnership, including costs for rendering corporate staff and support services to us, if any. There is no limit on the amount of expenses for which our manager and its affiliates may be reimbursed. Our partnership agreement provides that our general partner will determine the expenses that are allocable to us. In addition, to the extent our general partner incurs obligations on behalf of us, we are obligated to reimburse or indemnify our general partner. If we are unable or unwilling to reimburse or indemnify our general partner, our general partner may take actions to cause us to make payments of these obligations and liabilities. Any such payments could reduce the amount of cash otherwise available for distribution to our unitholders.

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

The general partner may transfer its general partner interest in us to a third party in a merger or in a sale of all or substantially all of its assets without the consent of the unitholders. Furthermore, there is no restriction in the partnership agreement on the ability of (i) ENLC to transfer all or a portion of its ownership interest in the general partner to a third party or (ii) Devon to transfer all or a portion of its ownership interest in ENLC and/or ENLC's manager to a third party. The new owner of the general partner or ENLC's manager, as the case may be, would then be in a position to replace the board of directors and officers of the general partner with its own choices and to control the decisions taken by the board of directors and officers.

Our general partner's absolute discretion in determining the level of cash reserves may adversely affect our ability to make cash distributions to our unitholders.

Our partnership agreement requires our general partner to deduct from operating surplus cash reserves that in its reasonable discretion are necessary to fund our future operating expenditures. In addition, the partnership agreement permits our general partner to reduce available cash by establishing cash reserves for the proper conduct of our business, to comply with applicable law or agreements to which we are a party or to provide funds for future distributions to partners. These cash reserves will affect the amount of cash available for distribution to our unitholders.

Our partnership agreement replaces the fiduciary duties otherwise owed to our unitholders by our general partner with contractual standards governing its duties and restricts the remedies available to our unitholders for actions that might otherwise constitute a breach of fiduciary duty by our general partner.

Our partnership agreement contains provisions that eliminate and replace the fiduciary standards that our general partner would otherwise be held to by state fiduciary duty law. 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, or otherwise, free of fiduciary duties to our unitholders. This entitles our general partner to consider only the interests and factors that it desires, and it has no duty or obligation to give any consideration to any interest of, or factors affecting our unitholders. Examples of decisions that our general partner may make in its individual capacity include:

- how to allocate business opportunities among us and its other affiliates;

- whether to exercise its call right;
- whether or not to consent to any merger or consolidation of us or any amendment to our partnership agreement; and
- whether or not the general partner should elect to seek the approval of the conflicts committee or the unitholders, or neither, of any conflicted transaction.

The partnership agreement also restricts the remedies available to our unitholders for actions that would otherwise constitute breaches of our general partner's fiduciary duties. By purchasing any of our common units, a unitholder is treated as having consented to the provisions in our partnership agreement, including the provisions discussed above.

We may issue additional units, including units that are senior to our common units and pari passu, with our Series C Preferred Units, without our unitholders' approval, which would dilute our unitholders' ownership interests.

We may issue an unlimited number of limited partner interests of any type without the approval of our unitholders. These additional limited partner interests may include any securities in parity with the Series C Preferred Units without any vote of the holders of the Series C Preferred Units (except where the cumulative distributions on the Series C Preferred Units or any parity securities are in arrears and in certain other circumstances) and without the approval of our common unitholders. The issuance of additional limited partner interests 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 cash available for distribution on each unit may decrease;
- the relative voting strength of each previously outstanding unit may be diminished; and
- the market price of the common units may decline.

Additionally, although holders of the Series C Preferred Units are entitled to limited voting rights, with respect to certain matters the Series C Preferred Units generally vote separately as a class along with all other series of our parity securities that we may issue with respect to which like voting rights have been conferred and are exercisable. As a result, the voting rights of holders of Series C Preferred Units may be significantly diluted, and the holders of such other series of parity securities that we may issue may be able to control or significantly influence the outcome of any vote. The issuance of additional units on parity with or senior to the Series C Preferred Units would dilute the interests of the holders of the Series C Preferred Units, and any issuance of equity securities of any class or series that ranks on parity with the Series C Preferred Units as to the payment of distributions and amounts payable upon a liquidation event or additional indebtedness could affect our ability to pay distributions on, redeem or pay the liquidation preference on the Series C Preferred Units.

Future issuances and sales of parity securities, or the perception that such issuances and sales could occur, may cause prevailing market prices for the Series C Preferred Units and our common units to decline and may adversely affect our ability to raise additional capital in the financial markets at times and prices favorable to us.

Furthermore, the payment of distributions on any additional units may increase the risk that we will not be able to make distributions at our prior per unit distribution levels. To the extent new units are senior to our common units, their issuance will increase the uncertainty of the payment of distributions on our common units.

If we do not pay distributions on our Series B Preferred Units and Series C Preferred Units, we will be unable to pay distributions on our common units until all unpaid Series B Preferred Units and Series C Preferred Unit distributions have been paid, and our common unitholders are not entitled to receive distributions for such prior period.

The Series B Preferred Units and Series C Preferred Units rank senior to our common units with respect to distribution rights and rights upon liquidation. If we do not pay the required distributions on our Series B Preferred Units and Series C Preferred Units, we will be unable to pay distributions on our common units. Additionally, because distributions to our Series B Preferred Units and Series C Preferred Unitholders are cumulative, we will have to pay all unpaid accumulated preferred distributions before we can pay any distributions to our common unitholders. Also, because distributions to our common unitholders are not cumulative, if we do not pay distributions on our common units with respect to any quarter, our common unitholders will not be entitled to receive distributions covering any prior periods.

In addition, in the event of our liquidation, winding-up or dissolution, the holders of the Series B Preferred Units and Series C Preferred Units would have the right to receive proceeds from any such transaction before the holders of our common units. The payment of these liquidation preferences could result in common unitholders not receiving any consideration if we were to liquidate, dissolve or wind up, either voluntarily or involuntarily. Additionally, the existence of these liquidation preferences may reduce the value of our common units, make it harder for us to sell common units in offerings in the future, or prevent or delay a change of control. The preferences and privileges of the Series B Preferred Units and Series C Preferred Units could adversely affect the market price for our common units, or could make it more difficult for us to sell our common units in the future.

In connection with the January 2016 issuance of the Series B Preferred Units, we entered into an agreement with TPG VII Management, LLC (“TPG”), an affiliate of Enfield Holdings, L.P., the holder of our Series B Preferred Units (“Enfield”), pursuant to which we granted them the right to appoint one member to the board of directors of our general partner. In addition, Enfield has the right to vote, under certain conditions, on an as-converted basis with our common unitholders on matters submitted to a unitholder vote. Also, as long as any Series B Preferred Units are outstanding, subject to certain exceptions, the affirmative vote or consent of the holders of at least a majority of the outstanding Series B Preferred Units, voting together as a separate class, will be necessary for, among other things: (i) any action to be taken that adversely affects any of the rights, preferences or privileges of the Series B Preferred Units, (ii) amending the terms of the Series B Preferred Units, (iii) the issuance of any limited partner interests that are senior or in parity in right of distribution or in liquidation to the Series B Preferred Units, subject to certain exceptions, and (iv) the ability to incur funded indebtedness for borrowed money if, immediately after the incurrence thereof and giving pro forma effect to the use of proceeds thereof, the consolidated leverage ratio (as defined in the credit agreement governing our credit facility) would exceed (a) 5.50 to 1.00 if such indebtedness is not incurred during an acquisition period (as defined in the credit agreement governing our credit facility) or (b) 6.00 to 1.00 such indebtedness is incurred during an acquisition period. These restrictions may adversely affect our ability to finance future operations or capital needs or to engage in other business activities.

Furthermore, the Series B Preferred Units are convertible into common units (i) in full or in part, at any time, at Enfield’s option or (ii) in full, at our option, in certain circumstances. Please read “Item 8. Financial Statements and Supplementary Data-Note 8(c)” for additional information concerning the Series B Preferred Units. Such conversion may cause substantial dilution to holders of the common units.

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

If at any time our general partner and its affiliates own more than 80.0% of the common units, our general partner will have the right, but not the obligation, which it may assign to any of its affiliates or to us, to acquire all, but not less than all, of the common units held by unaffiliated persons at a price equal to the greater of (1) their then-current market price and (2) the highest per-unit price paid by our general partner or any of its affiliates for our common units during the 90-day period preceding the date such notice is first mailed. As a result, our unitholders may be required to sell their common units at an undesirable time or price and may therefore not receive any return on their investment. Existing unitholders may also incur a tax liability upon a sale of their units. Our general partner is not obligated to obtain a fairness opinion regarding the value of our common units to be repurchased by it upon exercise of the call right. There is no restriction in our partnership agreement that prevents our general partner from issuing additional common units and exercising its call right. If our general partner exercised its call right, the effect would be to take us private. As of December 31, 2017, ENLC and its affiliates, including Devon, owned 52.4% of our outstanding common units.

ENLC or its affiliates, including our largest holder Devon, may sell units in the public or private markets, and such sales could have an adverse impact on the trading price of the common units.

As of December 31, 2017, ENLC and its affiliates, including our largest holder Devon, held an aggregate of 183,189,051 units. The sale of any or all of these units in the public or private markets could have an adverse impact on the price of common units or on any trading market on which common units are held.

The price of our common units may fluctuate significantly, which could cause our unitholders to lose all or part of their investment.

As of December 31, 2017, only approximately 47.6% of our common units were held by public unitholders. The lack of liquidity may result in wide bid-ask spreads, contribute to significant fluctuations in the market price of our common units and limit the number of investors who are able to buy our common units. The market price of our common units may be influenced by many factors, some of which are beyond our control, including:

- the quarterly distributions paid by us with respect to our common units;
- our quarterly or annual earnings or those of other companies in our industry;

- the loss of Devon as a customer;
- events affecting Devon;
- announcements by us or our competitors of significant contracts or acquisitions;
- changes in accounting standards, policies, guidance, interpretations or principles;
- general economic conditions;
- the failure of securities analysts to cover our common units or changes in financial estimates by analysts;
- future sales of our common units; and
- other factors described in these “Risk Factors.”

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

Our unitholders could be held liable for our obligations to the same extent as a general partner if a court determined that the right or the exercise of the right by our unitholders to remove or replace our general partner, to approve amendments to our partnership agreement, or to take other action under our partnership agreement constituted participation in the “control” of our business, to the extent that a person who has transacted business with the Partnership reasonably believes, based on our unitholders’ conduct, that our unitholders are a general partner. Our general partner generally has unlimited liability for the obligations of our partnership, such as its debts and environmental liabilities, except for those contractual obligations of our partnership that are expressly made without recourse to our general partner. In addition, Section 17-607 of the Delaware Revised Uniform Limited Partnership Act (the “Delaware Act”) provides that a limited partner who receives a distribution and knew at the time of the distribution that the distribution was in violation of that section may be liable to the limited partnership for the amount of the distribution for a period of three years from the date of the distribution. 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 do business.

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 exempts us from the following corporate governance requirements:

- the requirement that a majority of the board consist of independent directors;
- the requirement that the board of directors have a nominating or corporate governance committee, composed entirely of independent directors, that is responsible for identifying individuals qualified to become board members, consistent with criteria approved by the board, selection of board nominees for the next annual meeting of equity holders, development of corporate governance guidelines and oversight of the evaluation of the board and management;
- the requirement that we have a compensation committee of the board, composed entirely of independent directors, that is responsible for reviewing and approving corporate goals and objectives relevant to chief executive officer compensation, evaluation of the chief executive officer’s performance in light of the goals and objectives, determination and approval of the chief executive officer’s compensation, making recommendations to the board with respect to compensation of other executive officers and incentive compensation and equity-based plans that are subject to board approval and producing a report on executive compensation to be included in an annual proxy statement or Form 10-K filed with the SEC;
- the requirement that we conduct an annual performance evaluation of the nominating, corporate governance and compensation committees; and
- the requirement that we have written charters for the nominating, corporate governance and compensation committees addressing the committees’ responsibilities and annual performance evaluations.

For so long as we remain a publicly traded limited partnership, we will not be required to have a majority of independent directors or nominating, corporate governance or compensation committees. 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 Act, a limited partnership cannot make a distribution to its limited partners if, after the distribution, all liabilities, other than liabilities to unitholders on account of their limited partner interests and liabilities for which the recourse of creditors is limited to specific property of the limited partnership, would exceed the fair value of the assets of the limited partnership. For the purpose of determining the fair value of the assets of a limited partnership, the Delaware Act provides that the fair value of property subject to liability for which recourse of creditors is limited shall be included in the assets of the limited partnership only to the extent that the fair value of that property exceeds the non-recourse liability. The Delaware Act provides that a limited partner who receives a distribution and knew at the time of the distribution that the distribution was in violation of the Delaware Act will be liable to the limited partnership for the amount of the distribution for three years.

Tax Risks to Our Unitholders

Our tax treatment and our being subject to entity level taxation by individual states depends on our status as a partnership for federal income tax purposes. If the IRS treats us as a corporation or we become subject to entity level taxation for state tax purposes, it would substantially reduce the amount of cash available for distribution to our unitholders.

The anticipated after-tax economic benefit of an investment in us depends largely on our being treated as a partnership for federal income tax purposes.

If we were treated as a corporation for federal income tax purposes, we would pay additional tax on our income at corporate rates of up to 21% for taxable years beginning on or after January 1, 2018 (under the law as of the date of this report), and 35% to the extent we were treated as a corporation in any taxable years ending prior to January 1, 2018, and we would probably pay state income taxes as well. In addition, distributions to unitholders would generally be taxed again as corporate distributions, and none of our income, gains, losses or deductions would flow through to unitholders. Because a tax would be imposed upon us as a corporation, the cash available for distribution to unitholders would be substantially reduced. Therefore, treatment of us as a corporation would result in a material reduction in the anticipated cash flow and after-tax return to the unitholders and thus would likely result in a material reduction in the value of the common units.

In addition, recently enacted legislation applicable to partnership tax years beginning after 2017 changes the audit procedures for large partnerships and in certain circumstances would permit the IRS to assess and collect taxes (including any applicable penalties and interest) resulting from partnership-level federal income tax audits directly from us in the year in which the audit is completed. If we are required to make payments of taxes, penalties and interest resulting from audit adjustments, our cash available for distribution to our unitholders might be substantially reduced.

Moreover, changes in current state law may subject us to entity-level taxation by individual states. Because of widespread state budget deficits, several states are evaluating ways to subject partnerships to entity level taxation through the imposition of state income, franchise and other forms of taxation. For example, we are required to pay Texas franchise tax at a maximum effective rate of 0.75% of our taxable margin apportioned to Texas in the prior year. If additional state tax were to be imposed on us, the cash available for distribution to unitholders could be reduced and/or the value of an investment in our common units would be adversely impacted.

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 will be decreased to reflect the impact of that law on us. No such adjustments have been made to date, but there can be no assurance that no such adjustments will be made in the future.

If the IRS contests the federal income tax positions we take, the market for our common units may be adversely impacted and the costs of any contest could reduce the cash available for distribution to our unitholders.

We have not requested any ruling from the IRS with respect to our treatment as a partnership for federal income tax purposes or any other matter affecting us. The IRS may adopt positions that differ from our counsel’s conclusions expressed in this Annual Report or from the positions we take. 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. A court may not agree with all of our counsel’s conclusions or the positions we take. Any contest with the IRS may materially and adversely impact the market for our common units and the prices at which our common units trade. In addition, our costs of any contest with the IRS will be borne by us and therefore indirectly by our unitholders and our general partner since such costs will reduce the amount of cash available for distribution by us.

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, in which case we may require our unitholders and former unitholders to reimburse us for such taxes (including any applicable penalties or interest) or, if we are required to bear such payment, our cash available for distribution to our unitholders might be substantially reduced.

If the IRS makes audit adjustments to income tax returns for tax years beginning after 2017, it may assess and collect 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, we may require our unitholders and former unitholders to reimburse us for such taxes (including any applicable penalties or interest) or, if we are required to bear such payment, our cash available for distribution to our unitholders might be substantially reduced. In addition, because payment would be due for the taxable year in which the audit is completed, unitholders during that taxable year would bear the expense of the adjustment even if they were not unitholders during that taxable year.

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

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

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

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

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

Unitholders who sell common units will recognize gain or loss equal to the difference between the amount realized and their tax basis in those common units. Because distributions in excess of the unitholder's allocable share of total net taxable income decrease the unitholder's tax basis in his or her units, the amount, if any, of such prior excess distributions with respect to the units sold by the unitholder, will, in effect, become taxable income to the unitholder if the common unit is sold at a price greater than the tax basis in that common unit, even if the price received is less than the original cost. Furthermore, a substantial portion of the amount realized, whether or not representing gain, may be taxed as ordinary income to the unitholder due to potential recapture items, including depreciation recapture. In addition, because the amount realized includes a unitholder's share of our non-recourse liabilities, a unitholder who sells units may incur a tax liability in excess of the amount of cash received from the sale.

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

Investment in common units by tax-exempt entities, such as individual retirement accounts (known as IRAs), pension plans, and non-U.S. persons, raises issues unique to them. For example, virtually all of our income allocated to organizations exempt from federal income tax, including individual retirement accounts and other qualified retirement plans, will be unrelated business 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 federal income tax returns and generally pay tax on their share of our taxable income. If you are a tax-exempt entity or a foreign person, you should consult your tax advisor before investing in our common units.

Under the recently enacted Tax Cuts and Jobs Act, if a unitholder sells or otherwise disposes of a common unit, the transferee is required to withhold 10% of the amount realized by the transferor unless the transferor certifies that it is not a foreign person, and we are required to deduct and withhold from the transferee amounts that should have been withheld by the transferee but were not withheld. However, the Department of the Treasury and the IRS have determined that this withholding requirement should not apply to any disposition of a publicly traded interest in a publicly traded partnership (such as us) until regulations or other guidance have been issued clarifying the application of this withholding requirement to dispositions of such interests. Accordingly, while this new withholding requirement does not currently apply to interests in us, there can be no assurance that such requirement will not apply in the future.

We will treat each purchase of common units as having the same tax benefits without regard to the specific units purchased. 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 take 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 unitholders. It also could affect the timing of these tax benefits or the amount of gain from the sale of common units and could have a negative impact on the value of our common units or result in audit adjustments to the tax returns of unitholders.

Treatment of distributions on our Series C Preferred Units as guaranteed payments for the use of capital creates a different tax treatment for the holders of Series C Preferred Units than the holders of our common units.

The tax treatment of distributions on our Series C Preferred Units is uncertain. We will treat the holders of Series C Preferred Units as partners for tax purposes and will treat distributions on the Series C Preferred Units as guaranteed payments for the use of capital that will generally be taxable to the holders of Series C Preferred Units as ordinary income. Although a holder of Series C Preferred Units could recognize taxable income from the accrual of such a guaranteed payment even in the absence of a contemporaneous distribution, we anticipate accruing and making the guaranteed payment distributions semi-annually on the 15th day of June and December through and including December 15, 2022 and, thereafter, quarterly on the 15th day of March, June, September and December of each year. Because the guaranteed payment for each unit must accrue as income to a holder during the taxable year of the accrual, the guaranteed payment attributable to the period beginning December 15 and ending December 31 will accrue as income to the holder of record of a Series C Preferred Unit on December 31 for such period, regardless of whether such holder continues to own the Series C Preferred Unit at the time the actual distribution is made. Otherwise, the holders of Series C Preferred Units are generally not anticipated to share in our items of income, gain, loss or deduction, nor will we allocate any share of our nonrecourse liabilities to the holders of Series C Preferred Units. If the Series C Preferred Units were treated as indebtedness for tax purposes, rather than as guaranteed payments for the use of capital, distributions likely would be treated as payments of interest by us to the holders of Series C Preferred Units.

Investment in the Series C Preferred Units by tax-exempt investors, such as employee benefit plans and individual retirement accounts ("IRAs"), and non-U.S. persons raises issues unique to them. Although the issue is not free from doubt, we will treat distributions to non-U.S. holders of Series C Preferred Units as "effectively connected income" subject to withholding taxes. If the amount of withholding exceeds the amount of U.S. federal income tax actually due, non-U.S. holders of Series C Preferred Units may be required to file U.S. federal income tax returns in order to seek a refund of such excess. The treatment of guaranteed payments for the use of capital to tax-exempt investors is not certain and such payments may be treated as unrelated business taxable income for federal income tax purposes. If you are a tax-exempt entity or a non-U.S. person, you should consult your tax advisor with respect to the consequences of owning our Series C Preferred Units.

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, 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. For example, from time to time, the President and members of Congress propose and consider substantive changes to the existing federal income tax laws that affect publicly traded partnerships, including elimination of partnership tax treatment for publicly traded partnerships. Any modification to the federal income tax laws and interpretations thereof may or may not be retroactively applied and could make it more difficult or impossible for us to meet the requirements that must be satisfied in order for us to be treated as a partnership for federal income tax purposes.

We are unable to predict whether any of these changes, or other proposals, will ultimately be enacted. Any such changes could negatively impact the value of an investment in our common units. 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 income tax purposes, the minimum quarterly distribution and the target distribution levels will be adjusted to reflect the impact of that law on us.

We will adopt certain valuation methodologies and monthly conventions for 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.

Entity level taxes on income from our C corporation subsidiary will reduce cash available for distribution, and a unitholder's share of dividend and interest income from such subsidiary will constitute portfolio income that cannot be offset by the unitholder's share of other losses or deductions.

A portion of our taxable income is earned through a C corporation subsidiary. Such C corporation subsidiary is subject to federal income tax on its taxable income at the corporate tax rate, which is currently a maximum of 21%, and will likely pay state (and possibly local) income tax at varying rates, on its taxable income. Any such entity level taxes will reduce the cash available for distribution to our unitholders. Distributions from such C corporation subsidiary will generally be taxed again to unitholders as dividend income to the extent of current and accumulated earnings and profits of such subsidiary. Currently, the maximum federal income tax rate applicable to such dividend income which is allocable to individuals is 20% plus an unearned income Medicare tax of 3.8%. An individual unitholder's share of dividend and interest income from our C corporation subsidiary would constitute portfolio income that could not be offset by the unitholder's share of our other losses or deductions.

As a result of investing in our common units, you will likely be subject to state and local taxes and return filing or withholding requirements in jurisdictions where you do not live.

In addition to federal income taxes, you will likely be subject to other taxes such as state and local income taxes, unincorporated business taxes and estate, inheritance or intangible taxes that are imposed by the various jurisdictions in which we do business or own property. You will likely be required to file state and local tax returns and pay state and local income taxes in some or all of the various jurisdictions in which we do business or own property and you may be subject to penalties for failure to comply with those requirements. We own property or conduct business in a number of states, most of which currently impose a state income tax on individuals. Most of these states also impose an income tax on corporations and other entities. As we make acquisitions or expand our business, we may do business or own property in other states that impose an income tax. It is our unitholders' responsibility to file all federal, state, local, and foreign tax returns. Under the tax laws of some states where we will conduct business, we may be required to withhold a percentage from amounts to be distributed to a unitholder who is not a resident of that state. Our counsel has not rendered an opinion on the state, local, or foreign tax consequences of owning our common units.

We prorate our items of income, gain, loss and deduction 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 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. Treasury Department and the IRS recently issued final Treasury Regulations pursuant to which a publicly traded partnership may use a similar monthly simplifying convention to allocate tax items among transferor and transferee unitholders although such tax items must be prorated on a daily basis. However, these Treasury Regulations do not specifically authorize the use of the proration method we have adopted. If the IRS were to successfully challenge our proration method, we may be required to change the allocation of items of income, gain, loss and deduction among our unitholders.

A unitholder whose units are loaned to a "short seller" to cover a short sale of units may be considered as having disposed of those units. If so, he would no longer be treated for tax purposes as a partner with respect to those units during the period of the loan and may recognize gain or loss from the disposition.

Because a unitholder whose units are loaned to a "short seller" to cover a short sale of units may be considered as having disposed of the loaned units, he may no longer be treated for tax purposes as a partner with respect to those units during the period of the loan to the short seller and the unitholder 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 units may not be reportable by the unitholder and any cash distributions received by the unitholder as to those units could be fully taxable as ordinary income. Our counsel has not rendered an opinion regarding the treatment of a unitholder where common units are loaned to a short seller to cover a short sale of common units; therefore, 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 modify any applicable brokerage account agreements to prohibit their brokers from borrowing their units.

Compliance with and changes in tax law 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

We do not have any unresolved staff comments.

Item 2. Properties

A description of our properties is contained in "Item 1. Business."

Title to Properties

Substantially all of our pipelines are constructed on rights-of-way granted by the apparent record owners of the property. Lands over which pipeline rights-of-way have been obtained may be subject to prior liens that have not been subordinated to the right-of-way grants. We have obtained, where necessary, easement agreements from public authorities and railroad companies to cross over or under, or to lay facilities in or along, watercourses, county roads, municipal streets, railroad properties and state highways, as applicable. In some cases, property on which our pipeline was built was purchased in fee. Our processing plants are located on land that we lease or own in fee.

We believe that we have satisfactory title to all of our rights-of-way and land assets. Title to these assets may be subject to encumbrances or defects. We believe that none of such encumbrances or defects should materially detract from the value of our assets or from our interest in these assets or should materially interfere with their use in the operation of the business.

Item 3. Legal Proceedings

Our operations are subject to a variety of risks and disputes normally incident to our business. As a result, at any given time we may be a defendant in various legal proceedings and litigation arising in the ordinary course of business, including litigation on disputes related to contracts, property use or damage and personal injury. We may continue to see claims brought by landowners, such as nuisance claims and other claims based on property rights. Except as otherwise set forth herein, we do not believe that any pending or threatened claim or dispute is material to our financial condition, results of operations or cash flows. We maintain insurance policies with insurers in amounts and with coverage and deductibles that our general partner believes are reasonable and prudent. However, we cannot assure you that this insurance will be adequate to protect us from all material expenses related to potential future claims for personal and property damage or that these levels of insurance will be available in the future at economical prices.

At times, our subsidiaries acquire pipeline easements and other property rights by exercising rights of eminent domain and common carrier. As a result, from time to time we or our subsidiaries are party to lawsuits under which a court will determine the value of pipeline easements or other property interests obtained by our subsidiaries by condemnation. Damage awards in these suits should reflect the value of the property interest acquired and the diminution in the value of the remaining property owned by the landowner. However, some landowners have alleged unique damage theories to inflate their damage claims or assert valuation methodologies that could result in damage awards in excess of the amounts anticipated. Although it is not possible to predict the ultimate outcomes of these matters, we do not expect that awards in these matters will have a material adverse impact on our consolidated financial condition, results of operations or cash flows.

We (or our subsidiaries) are defending lawsuits filed by owners of property located near processing facilities or compression facilities that we own or operate as part of our systems. The suits generally allege that the facilities create a private nuisance and have damaged the value of surrounding property. Claims of this nature have arisen as a result of the industrial development of natural gas gathering, processing and treating facilities in urban and occupied rural areas.

We own and operate a high-pressure pipeline and underground natural gas and NGL storage reservoirs and associated facilities near Bayou Corne, Louisiana. In August 2012, a large sinkhole formed in the vicinity of this pipeline and underground storage reservoirs, resulting in damage to certain of our facilities. In order to recover our losses from responsible parties, we sued the operator of a failed cavern in the area, and its insurers, as well as other parties we alleged to have contributed to the formation of the sinkhole seeking recovery for these losses. We also filed a claim with our insurers, which our insurers denied. We disputed the denial and sued our insurers, and we subsequently reached settlements regarding the entirety of our claims in both lawsuits. In August 2014, we received a partial settlement with respect to our claims in the amount of $6.1 million. We secured additional settlement payments during 2017, which resulted in the recognition of “Gain on litigation settlement” of $26.0 million on the consolidated statement of operations for the year ended December 31, 2017.

Item 4. Mine Safety Disclosures

Not applicable.

PART II

Item 5. Market for Registrant's Common Equity, Related Unitholder Matters and Issuer Purchases of Equity Securities

Our common units are listed on the NYSE under the symbol"ENLK." On February 14, 2018, there were approximately 27,474 record holders and beneficial owners (held in street name) of our common units. For equity compensation plan information, see discussion under "Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Unitholder Matters—Equity Compensation Plan Information."

The following table shows the high and low closing sales prices percommon unit, as reported by the NYSE and cash distributions declared per common unit for the periods indicated:

	Range		Cash Distribution
	High	Low	Declared Per Unit
2017			
Quarter Ended December 31	$ 16.89	$ 14.60	$ 0.390
Quarter Ended September 30	17.48	14.69	0.390
Quarter Ended June 30	18.89	15.16	0.390
Quarter Ended March 31	19.45	17.32	0.390
2016			
Quarter Ended December 31	$ 18.62	$ 16.09	$ 0.390
Quarter Ended September 30	19.03	16.34	0.390
Quarter Ended June 30	17.06	10.74	0.390
Quarter Ended March 31	16.74	7.71	0.390

Unless restricted by the terms of our credit facility, within 45 days after the end of each quarter, we will distribute all of our available cash, as defined in our partnership agreement, to common unitholders of record on the applicable record date. Our available cash consists generally of all cash on hand at the end of the fiscal quarter plus all cash on hand on the date of determination resulting from working capital borrowings made after the end of the fiscal quarter, less reserves that our general partner determines are necessary to:

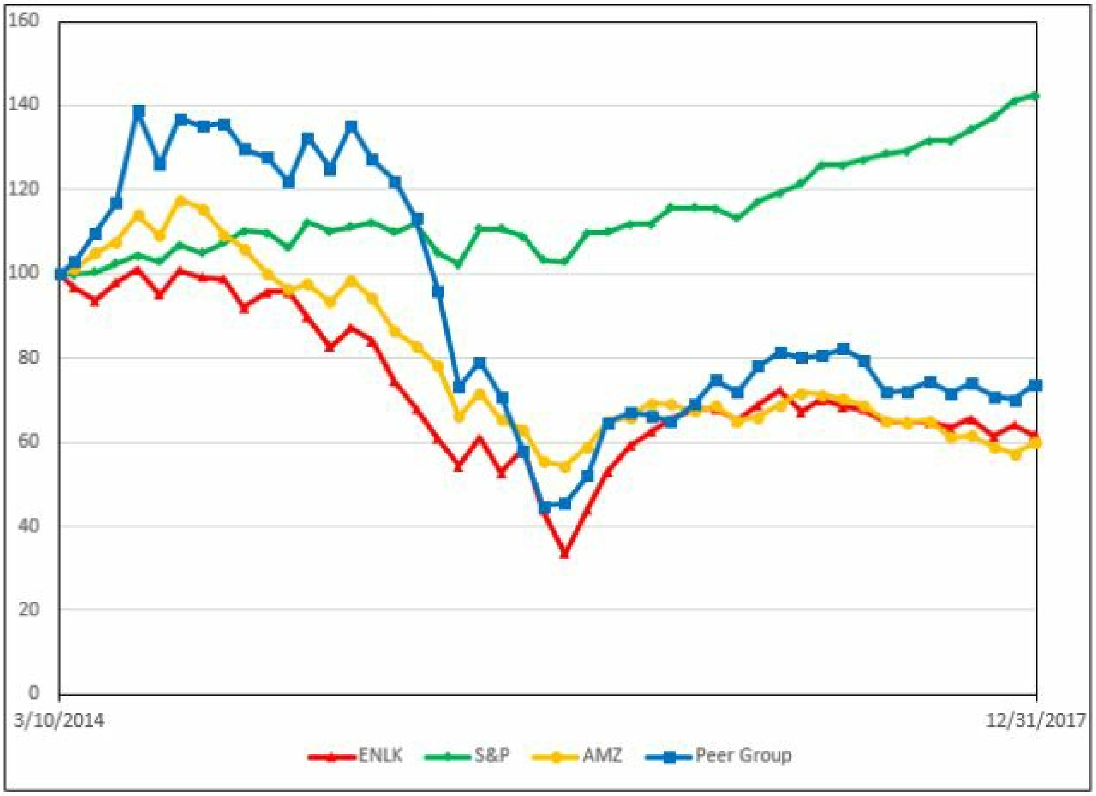
- provide for the proper conduct of our business;
- comply with applicable law, our debt instruments or other agreements; and
- provide funds for distributions to our unitholders and to our general partner for any one or more of the next four quarters.

Under our existing credit facility, we may be limited from making certain distributions if an event of default exists. Please read "Item 8. Financial Statements and Supplementary Data—Note 6" for additional information concerning our credit facility.

Our general partner has broad discretion to establish cash reserves that it determines are necessary or appropriate to properly conduct our business. These can include cash reserves for future capital and maintenance expenditures, reserves to stabilize distributions of cash to the unitholders and our general partner, reserves to reduce debt or, as necessary, reserves to comply with the terms of any of our agreements or obligations. Our distributions are made to our general partner based on its ownership interest with the remaining interest to unitholders, subject to the payment of incentive distributions to our general partner if certain target cash distribution levels to common unitholders are achieved. Incentive distributions to our general partner increase to 13.0%, 23.0% and 48.0% based on incremental distribution thresholds as set forth in our partnership agreement.

Performance Graph

The following graph sets forth the cumulative total stockholder return for our common units, the Standard & Poor's 500 Stock Index, Alerian MLP Index and a peer group of publicly traded limited partnerships in the midstream natural gas, natural gas liquids, propane, and pipeline industries for the year ended December 31, 2017. The chart assumes that $100 was invested on March 10, 2014, with distributions reinvested. The peer group includes MPLX, Energy Transfer Equity, L.P., Targa Resources, Inc. and Western Gas Equity Partners, L.P.



Item 6. Selected Financial Data

The historical financial statements included in this report reflect (1) for periods prior to March 7, 2014, the assets, liabilities and operations of EnLink Midstream Holdings, LP Predecessor (the "Predecessor"), the predecessor to Midstream Holdings, which is the historical predecessor of the Partnership and (2) for periods on or after March 7, 2014, the results of operations of the Partnership after giving effect to the Business Combination discussed under "Item 1. Business—General." The Predecessor was comprised of all of the U.S. midstream assets and operations of Devon prior to the Business Combination, including its 38.75% interest in GCF. However, in connection with the Business Combination, only the Predecessor's systems serving the Barnett, Cana-Woodford and Arkoma-Woodford Shales in Texas and Oklahoma, as well as the economic benefits and burdens of the 38.75% interest in GCF, were contributed to Midstream Holdings, effective as of March 7, 2014.

The following table presents our selected historical financial and operating data for the periods indicated. Financial and operating data for the years ended December 31, 2017, 2016, 2015 and 2014 reflect acquisitions and dispositions for periods subsequent to the applicable transaction date. The selected historical financial data should be read together with "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" and the consolidated financial statements and accompanying notes in "Item 8. Financial Statements and Supplementary Data."

	EnLink Midstream Partners, LP				
	Year Ended December 31,				
	2017	2016	2015	2014 (4)	2013 (4)
	(In millions, except per unit data)				
Revenues:					
Product sales	$ 4,358.4	$ 3,008.9	$ 3,253.7	$ 2,159.3	$ 179.4
Product sales—related parties	144.9	134.3	119.4	505.6	2,116.5
Midstream services	552.3	467.2	451.0	253.4	—
Midstream services—related parties	688.2	653.1	618.6	567.4	—
Gain (loss) on derivative activity	(4.2)	(11.1)	9.4	22.1	—
Total revenues	5,739.6	4,252.4	4,452.1	3,507.8	2,295.9
Operating costs and expenses:					
Cost of sales (1)	4,361.5	3,015.5	3,245.3	2,494.5	1,736.3
Operating expenses (2)	418.7	398.5	419.9	283.6	156.2
General and administrative (3)	123.5	119.3	132.4	94.5	45.1
(Gain) loss on disposition of assets	—	13.2	1.2	(0.1)	—
Depreciation and amortization	545.3	503.9	387.3	284.3	187.0
Impairments	17.1	566.3	1,563.4	—	—
Gain on litigation settlement	(26.0)	—	—	(6.1)	—
Total operating costs and expenses	5,440.1	4,616.7	5,749.5	3,150.7	2,124.6
Operating income (loss)	299.5	(364.3)	(1,297.4)	357.1	171.3
Other income (expense):					
Interest expense, net of interest income	(187.9)	(188.1)	(102.5)	(47.4)	—
Gain on extinguishment of debt	9.0	—	—	3.2	—
Income (loss) from unconsolidated affiliates	9.6	(19.9)	20.4	18.9	14.8
Other income (expense)	0.6	0.3	0.8	(0.5)	—
Total other income (expense)	(168.7)	(207.7)	(81.3)	(25.8)	14.8
Income (loss) from continuing operations before non-controlling interest and income taxes	130.8	(572.0)	(1,378.7)	331.3	186.1
Income tax (provision) benefit	24.0	(1.3)	0.5	(22.0)	(67.0)
Net income (loss) from continuing operations	154.8	(573.3)	(1,378.2)	309.3	119.1
Discontinued operations:					
Income (loss) from discontinued operations, net of tax	—	—	—	1.0	(2.3)
Income from discontinued operations attributable to non-controlling interest, net of tax	—	—	—	—	(1.3)
Discontinued operations, net of tax	—	—	—	1.0	(3.6)
Net income (loss)	154.8	(573.3)	(1,378.2)	310.3	115.5
Less: Net income (loss) from continuing operations attributable to the non-controlling interest	5.9	(8.1)	(0.4)	(0.2)	—
Net income (loss) attributable to EnLink Midstream Partners, LP	$ 148.9	$ (565.2)	$ (1,377.8)	$ 310.5	$ 115.5
Predecessor interest in net income	$ —	$ —	$ —	$ 35.5	$ —
General partner interest in net income	$ 38.3	$ 39.5	$ 58.0	$ 138.3	$ —
Limited partners' interest in net income (loss) attributable to EnLink Midstream Partners, LP	$ 17.9	$ (662.1)	$ (1,405.2)	$ 136.7	$ —
Class C partners' interest in net loss attributable to EnLink Midstream Partners, LP	$ —	$ (12.5)	$ (30.6)	$ —	$ —
Series B preferred interest in net income attributable to EnLink Midstream Partners, LP	$ 86.0	$ 69.9	$ —	$ —	$ —
Series C preferred interest in net income attributable to EnLink Midstream Partners, LP	$ 6.7	$ —	$ —	$ —	$ —
Net income (loss) attributable to EnLink Midstream Partners, LP per limited partners' unit:					
Basic and diluted common unit	$ 0.05	$ (1.99)	$ (4.66)	$ 0.59	$ —
Distributions declared per limited partner unit	$ 1.560	$ 1.560	$ 1.545	$ 1.470	$ —

(1) Includes related party cost of sales of $211.0 million, $150.1 million, $141.3 million, $354.3 million and $1,588.2 million for the years ended December 31, 2017, 2016, 2015, 2014 and 2013, respectively.
(2) Includes related party operating expense of $0.6 million, $0.5 million, $0.5 million, $5.9 million and $36.2 million for the years ended December 31, 2017, 2016, 2015, 2014 and 2013, respectively.
(3) Includes related party general and administrative expenses of $11.6 million and $45.1 million for the years ended December 31, 2014 and 2013, respectively. Related party general and administrative expenses, if any, subsequent to December 31, 2014, were not material.
(4) Prior to March 7, 2014, our financial results only included the assets, liabilities and operations of our Predecessor. Beginning on March 7, 2014, our financial results also consolidated the assets, liabilities and operations of the legacy business of the Partnership prior to giving effect to the Business Combination.

	EnLink Midstream Partners, LP Year Ended December 31,				
	2017	2016	2015	2014	2013
	(In millions, except per unit data)				
Balance Sheet Data (end of period):					
Property and equipment, net	$ 6,587.0	$ 6,256.7	$ 5,666.8	$ 5,042.8	$ 1,768.1
Total assets	9,414.0	9,153.4	8,092.8	8,702.0	2,309.8
Long-term debt (including current maturities)	3,467.8	3,268.0	3,066.8	2,022.5	—
Partners' equity including non-controlling interest	4,805.5	4,640.4	4,434.5	6,025.9	1,783.7

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

Please read the following discussion of our financial condition and results of operations in conjunction with the financial statements and notes thereto included elsewhere in this report.

In this report, the term "Partnership," as well as the terms "ENLK," "our," "we," "us" and "its," are sometimes used as abbreviated references to EnLink Midstream Partners, LP itself or EnLink Midstream Partners, LP together with its consolidated subsidiaries, including EnLink Midstream Operating, LP and EnLink Oklahoma Gas Processing, LP ("EnLink Oklahoma T.O."). EnLink Oklahoma T.O. is sometimes used to refer to EnLink Oklahoma Gas Processing, LP itself or EnLink Oklahoma Gas Processing, LP together with its consolidated subsidiaries. Readers are advised to refer to the context in which terms are used, and to read this report in conjunction with other information concerning our business in "Item 1A. Risk Factors" and otherwise.

Overview

We are a Delaware limited partnership formed on July 12, 2002. We primarily focus on providing midstream energy services, including:

- gathering, compressing, treating, processing, transporting, storing and selling natural gas;
- fractionating, transporting, storing, exporting and selling NGLs; and
- gathering, transporting, stabilizing, storing, trans-loading and selling crude oil and condensate.

Our midstream energy asset network includes approximately 11,000 miles of pipelines, 20 natural gas processing plants with approximately 4.8 Bcf/d of processing capacity, 7 fractionators with approximately 260,000 Bbls/d of fractionation capacity, barge and rail terminals, product storage facilities, purchasing and marketing capabilities, brine disposal wells, a crude oil trucking fleet, and equity investments in certain joint ventures. We manage and report our activities primarily according to the nature of activity and geography. We have five reportable segments:

- *Texas Segment.* The Texas segment includes our natural gas gathering, processing and transmission operations in North Texas and the Midland and Delaware Basins (together, the "Permian Basin") primarily in West Texas;

- *Oklahoma Segment*. The Oklahoma segment includes our natural gas gathering, processing and transmission activities in Cana-Woodford, Arkoma-Woodford, Northern Oklahoma Woodford, Sooner Trend Anadarko Basin Canadian and Kingfisher Counties ("STACK") and Central Northern Oklahoma Woodford Shale ("CNOW") areas;

- *Louisiana Segment*. The Louisiana segment includes our natural gas pipelines, natural gas processing plants, storage facilities, fractionation facilities and NGL assets located in Louisiana;

- *Crude and Condensate Segment.* The Crude and Condensate segment includes our Ohio River Valley ("ORV") crude oil, condensate, condensate stabilization, natural gas compression and brine disposal activities in the Utica and Marcellus Shales, our crude oil operations in the Permian Basin and Central Oklahoma and our crude oil activities associated with our Victoria Express Pipeline and related truck terminal and storage assets ("VEX") located in the Eagle Ford Shale; and

- *Corporate Segment*. The Corporate segment includes our unconsolidated affiliate investments in the Cedar Cove joint venture ("Cedar Cove JV") in Oklahoma, our contractual right to the economic benefits and burdens associated with Devon Energy Corporation's ("Devon") ownership interest in Gulf Coast Fractionators ("GCF") in South Texas and our general corporate property and expenses. Until March 2017, the Corporate segment included our unconsolidated affiliate investment in Howard Energy Partners ("HEP"), which we divested in March 2017.

We manage our operations by focusing on gross operating margin because our business is generally to gather, process, transport or market natural gas, NGLs, crude oil and condensate using our assets for a fee. We earn our fees through various fee-based contractual arrangements, which include stated fee-only contract arrangements or arrangements with fee-based components where we purchase and resell commodities in connection with providing the related service and earn a net margin as our fee. We earn our net margin under our purchase and resell contract arrangements primarily as a result of stated service-related fees that are deducted from the price of the commodity purchase. While our transactions vary in form, the essential element of each transaction is the use of our assets to transport a product or provide a processed product to an end-user or other marketer or pipeline at the tailgate of the plant, barge terminal or pipeline. We define gross operating margin as operating revenue minus cost of sales. Gross operating margin is a non-GAAP financial measure and is explained in greater detail under "Non-GAAP Financial Measures" below. Approximately 94% of our gross operating margin was derived from fee-based contractual arrangements with minimal direct commodity price exposure for the year ended December 31, 2017.We reflect revenue as "Product sales" and "Midstream services" on the consolidated statements of operations.

We generate revenues from eight primary sources:

- gathering and transporting natural gas, NGLs and crude oil on the pipeline systems we own;
- processing natural gas at our processing plants;
- fractionating and marketing recovered NGLs;
- providing compression services;
- providing crude oil and condensate transportation and terminal services;
- providing condensate stabilization services;
- providing brine disposal services; and
- providing natural gas, crude oil and NGL storage.

Our gross operating margins are determined primarily by the volumes of:

- natural gas gathered, transported, purchased and sold through our pipeline systems;
- natural gas processed at our processing facilities;
- NGLs handled at our fractionation facilities or transported through our pipeline systems;
- crude oil and condensate handled at our crude terminals;
- crude oil and condensate gathered, transported, purchased and sold;
- condensate stabilized;
- brine disposed; and
- natural gas, crude oil and NGLs stored.

We gather, transport or store gas owned by others under fee-only contract arrangements based either on the volume of gas gathered, transported or stored or, for firm transportation arrangements, a stated monthly fee for a maximum monthly quantity with an additional fee based on actual volumes. We also buy natural gas from producers or shippers at a market index less a fee-based deduction subtracted from the purchase price of the natural gas. We then gather or transport the natural gas and sell the natural gas at a market index, thereby earning a margin through the fee-based deduction. We attempt to execute substantially all purchases and sales concurrently, or we enter into a future delivery obligation, thereby establishing the basis for the fee we will receive for each natural gas transaction. We are also party to certain long-term gas sales commitments that we satisfy through supplies purchased under long-term gas purchase agreements. When we enter into those arrangements, our sales obligations generally match our purchase obligations. However, over time, the supplies that we have under contract may decline due to reduced drilling or other causes, and we may be required to satisfy the sales obligations by buying additional gas at prices that may exceed the prices received under the sales commitments. In our purchase/sale transactions, the resale price is generally based on the same index at which the gas was purchased.

On occasion, we have entered into certain purchase/sale transactions in which the purchase price is based on a production-area index and the sales price is based on a market-area index, and we capture the difference in the indices (also referred to as "basis spread"), less the transportation expenses from the two areas, as our fee. Changes in the basis spread can increase or decrease our margins or potentially result in losses. For example, we are a party to one contract associated with our North Texas operations with a term to July 2019 to supply approximately 150,000 MMBtu/d of gas. We buy gas for this contract on several different production-area indices and sell the gas into a different market area index. We realize a cash loss on the delivery of gas under this contract each month based on current prices. The fair value of this performance obligation was recorded based on forecasted discounted cash obligations in excess of market prices under this gas delivery contract. As of December 31, 2017, the balance sheet reflects a liability of $26.9 million related to this performance obligation. Narrower basis spreads in recent periods have increased the losses on this contract, and greater losses on this contract could occur in future periods if these conditions persist or become worse.

We typically buy mixed NGLs from our suppliers on our gas processing plants at a fixed discount to market indices for the component NGLs with a deduction for our fractionation fee. We subsequently sell the fractionated NGL products based on the same index-based prices. To a lesser extent, we transport and fractionate or store NGLs owned by others for a fee based on the volume of NGLs transported and fractionated or stored. The operating results of our NGL fractionation business are largely dependent upon the volume of mixed NGLs fractionated and the level of fractionation fees charged. With our fractionation business, we also have the opportunity for product upgrades for each of the discrete NGL products. We realize higher gross operating margins from product upgrades during periods with higher NGL prices.

We gather or transport crude oil and condensate owned by others by rail, truck, pipeline and barge facilities under fee-only contract arrangements based on volumes gathered or transported. We also buy crude oil and condensate from producers at a market index less a stated deduction, then transport and resell the crude oil and condensate at the same market index. We execute substantially all purchases and sales concurrently, thereby establishing the net margin we will receive for each crude oil and condensate transaction.

We realize gross operating margins from our gathering and processing services primarily through different contractual arrangements: processing margin (“margin”) contracts, percentage of liquids (“POL”) contracts, percentage of proceeds (“POP”) contracts, fixed-fee component contracts, or a combination of these contractual arrangements. See “Item 7A. Quantitative and Qualitative Disclosures about Market Risk—Commodity Price Risk” for a detailed description of these contractual arrangements. Under any of these gathering and processing arrangements, we may only earn a fee for the services performed, or we may buy and resell the gas and/or NGLs as part of the processing arrangement and realize a net margin as our fee. Under margin contract arrangements, our gross operating margins are higher during periods of high NGL prices relative to natural gas prices. Gross operating margin results under POL contracts are impacted only by the value of the liquids produced with margins higher during periods of higher liquids prices. Gross operating margin results under POP contracts are impacted only by the value of the natural gas and liquids produced with margins higher during periods of higher natural gas and liquids prices. Under fixed-fee based contracts, our gross operating margins are driven by throughput volume.

Operating expenses are costs directly associated with the operations of a particular asset. Among the most significant of these costs are those associated with direct labor and supervision, property insurance, property taxes, repair and maintenance expenses, contract services and utilities. These costs are normally fairly stable across broad volume ranges and therefore do not normally increase or decrease significantly in the short term with increases or decreases in the volume of gas, liquids, crude oil and condensate moved through or by the asset.

General and administrative expenses are dictated by the terms of our partnership agreement. These expenses include the costs of employee, officer and director compensation and benefits properly allocable to us, fees, services and other transaction costs related to acquisitions, and all other expenses necessary or appropriate to the conduct of business and allocable to us. Our partnership agreement provides that our general partner determines the expenses that are allocable to us in any reasonable manner determined by our general partner at its sole discretion.

Recent Growth Developments

Organic Growth

Central Oklahoma Plants. In 2017, we completed construction of two new cryogenic gas processing plants, which included the Chisholm II plant completed in April 2017 and the Chisholm III plant completed in December 2017. Each plant provides 200 MMcf/d of processing capacity and is connected to new and existing gathering pipeline and compression assets in the STACK play in Oklahoma. The new capacity is supported by new and existing long-term contracts.

In addition, we are constructing an additional 200 MMcf/d gas processing plant, referred to as the “Thunderbird plant” to expand our Central Oklahoma processing capacity. We expect to begin operations on the Thunderbird plant during the first quarter of 2019.

In June 2017, we entered into a long-term, fee-based arrangement with Oneok Partners (“Oneok”) under which Oneok transports NGLs from our Chisholm processing facility to the Gulf Coast and our Cajun-Sibon system. The agreement allows us to retain control of volumes and preferentially fill our Cajun-Sibon system.

Black Coyote Crude Oil Gathering System. In the fourth quarter of 2017, we began construction of a new crude oil gathering system that we refer to as "Black Coyote," which will expand our operations in the core of the STACK play in Central Oklahoma. Black Coyote is being built primarily on acreage dedicated from Devon, which will be the main shipper on the system. The system is expected to be operational in the first quarter of 2018.

Lobo Natural Gas Gathering and Processing Facilities. The Lobo facilities are part of our joint venture (the "Delaware Basin JV") with an affiliate of NGP Natural Resources XI, LP ("NGP") and are supported by long-term contracts. In the first quarter of 2017, we completed the expansion of a 75-mile gathering system for our Lobo II processing facility. In the second quarter of 2017, we completed the construction of an expansion of the Lobo II processing facility, which provided an additional 60 MMcf/d of processing capacity to the existing 95 MMcf/d provided by the Lobo processing facilities. Furthermore, we are constructing an additional expansion of the Lobo II processing facility, which will increase capacity by 15 MMcf/d and is expected to be completed during the first half of 2018. In 2018, we will also expand our gas processing capacity at our Lobo facilities by 200 MMcf/d through the construction of the Lobo III cryogenic gas processing plant, which is expected to be operational around the second half of 2018.

Greater Chickadee Crude Oil Gathering System. In March 2017, we completed construction and began operations of a crude oil gathering system in Upton and Midland counties, Texas in the Permian Basin, which we refer to as "Greater Chickadee." Greater Chickadee includes over 185 miles of high- and low-pressure pipelines that transport crude oil volumes to several major market outlets and other key hub centers in the Midland, Texas area and is supported by long-term contracts. Greater Chickadee also includes multiple central tank batteries, together with pump, truck injection and storage stations to maximize shipping and delivery options for our producer customers.

Marathon Petroleum Joint Venture. In April 2017, we completed construction and began operating a new NGL pipeline, which is part of our 50/50 joint venture with a subsidiary of Marathon Petroleum Company ("Marathon Petroleum"). This joint venture, Ascension Pipeline Company, LLC (the "Ascension JV"), is a bolt-on project to our Cajun-Sibon NGL system and is supported by long-term, fee-based contracts with Marathon Petroleum.

Sale of Non-Core Assets

In March 2017, we completed the sale of our ownership interest in HEP for net proceeds of $189.7 million. For the year ended December 31, 2016, we recorded an impairment loss of $20.1 million to reduce the carrying value of our investment to the expected sales price. Upon the sale of HEP in March 2017, we recorded an additional loss of $3.4 million for the year ended December 31, 2017 based on the adjusted sales price at closing.

Redemption of Senior Unsecured Notes due 2022

On June 1, 2017, we redeemed $162.5 million in aggregate principal amount of our 7.125% senior unsecured notes (the "2022 Notes") at 103.6% of the principal amount, plus accrued unpaid interest, for aggregate cash consideration of $174.1 million, which resulted in a gain on extinguishment of debt of $9.0 million for the year ended December 31, 2017.

Issuance of Senior Notes

On May 11, 2017, we issued $500.0 million in aggregate principal amount of our 5.450% senior unsecured notes due June 1, 2047 (the "2047 Notes") at a price to the public of 99.981% of their face value. Interest payments on the 2047 Notes are payable on June 1 and December 1 of each year. Net proceeds of approximately $495.2 million were used to repay outstanding borrowings under our credit facility and for general partnership purposes.

On July 14, 2016, we issued $500.0 million in aggregate principal amount of our 4.850% senior notes due 2026 (the "2026 Notes") at a price to the public of 99.859% of their face value. The 2026 Notes mature on July 15, 2026. Interest payments on the 2026 Notes are payable on January 15 and July 15 of each year. Net proceeds of approximately $495.7 million were used to repay outstanding borrowings under our credit facility and for general partnership purposes.

Equity Issuances

Issuance of Common Units. In November 2014, we entered into an Equity Distribution Agreement (the "2014 EDA") with BMO Capital Markets Corp. and other sales agents to sell up to $350.0 million in aggregate gross sales of our common units from time to time through an "at the market" equity offering program. In August 2017, we ceased trading under the 2014 EDA and entered into an Equity Distribution Agreement (the "2017 EDA") with UBS Securities LLC and other sales agents (collectively, the "Sales Agents") to sell up to $600.0 million in aggregate gross sales of our common units from time to time through an "at the market" equity offering program. We may also sell common units to any Sales Agent as principal for the Sales Agent's own account at a price agreed upon at the time of sale. We have no obligation to sell any of our common units under the 2017 EDA and may at any time suspend solicitation and offers under the 2017 EDA.

For the year ended December 31, 2017, we sold an aggregate of approximately 6.2 million common units under the 2014 EDA and the 2017 EDA, generating proceeds of approximately $106.9 million (net of approximately $1.1 million of commissions and $0.2 million of registration fees). We used the net proceeds for general partnership purposes. As of December 31, 2017, approximately $565.4 million remains available to be issued under the 2017 EDA.

Issuance of Series C Preferred Units. In September 2017, we issued 400,000 Series C Fixed-to-Floating Rate Cumulative Redeemable Perpetual Preferred Units (the "Series C Preferred Units") representing our limited partner interests at a price to the public of $1,000 per unit. We used the net proceeds of $394.0 million for capital expenditures, general partnership purposes and to repay borrowings under our credit facility. The Series C Preferred Units represent perpetual equity interests in us and, unlike our indebtedness, will not give rise to a claim for payment of a principal amount at a particular date. As to the payment of distributions and amounts payable on a liquidation event, the Series C Preferred Units rank senior to our common units and to each other class of limited partner interests or other equity securities established after the issue date of the Series C Preferred Units that is not expressly made senior or on parity with the Series C Preferred Units. The Series C Preferred Units rank junior to the Series B Preferred Units with respect to the payment of distributions, and junior to the Series B Preferred Units and all current and future indebtedness with respect to amounts payable upon a liquidation event.

At any time on or after December 15, 2022, we may redeem, at our option, in whole or in part, the Series C Preferred Units at a redemption price in cash equal to $1,000 per Series C Preferred Unit plus an amount equal to all accumulated and unpaid distributions, whether or not declared. We may undertake multiple partial redemptions. In addition, at any time within 120 days after the conclusion of any review or appeal process instituted by us following certain rating agency events, we may redeem, at our option, the Series C Preferred Units in whole at a redemption price in cash per unit equal to $1,020 plus an amount equal to all accumulated and unpaid distributions, whether or not declared.

Distributions on the Series C Preferred Units accrue and are cumulative from the date of original issue and payable semi-annually in arrears on the 15th day of June and December of each year through and including December 15, 2022 and, thereafter, quarterly in arrears on the 15th day of March, June, September and December of each year, in each case, if and when declared by our general partner out of legally available funds for such purpose. The initial distribution rate for the Series C Preferred Units from and including the date of original issue to, but not including, December 15, 2022 is 6.0% per annum. On and after December 15, 2022, distributions on the Series C Preferred Units will accumulate for each distribution period at a percentage of the $1,000 liquidation preference per unit equal to an annual floating rate of the three-month LIBOR plus a spread of 4.11%.

Issuance of Series B Preferred Units. In January 2016, we issued an aggregate of 50,000,000 Series B Preferred Units representing our limited partner interests to Enfield Holdings, L.P. ("Enfield") in a private placement for a cash purchase price of $15.00 per Series B Preferred Unit (the "Issue Price"), resulting in net proceeds of approximately $724.1 million after fees and deductions. Proceeds from the private placement were used to partially fund our portion of the purchase price payable in connection with the acquisition of our EnLink Oklahoma T.O. assets. Affiliates of the Goldman Sachs Group, Inc. and affiliates of TPG Global, LLC own interests in the general partner of Enfield. The Series B Preferred Units are convertible into our common units on a one-for-one basis, subject to certain adjustments, (a) in full, at our option, if the volume weighted average price of a common unit over the 30-trading day period ending two trading days prior to the conversion date (the "Conversion VWAP") is greater than 150% of the Issue Price or (b) in full or in part, at Enfield's option. In addition, upon certain events involving a change of control of our general partner or the managing member of ENLC, all of the Series B Preferred Units will automatically convert into a number of common units equal to the greater of (i) the number of common units into which the Series B Preferred Units would then convert and (ii) the number of Series B Preferred Units to be converted multiplied by an amount equal to (x) 140% of the Issue Price divided by (y) the Conversion VWAP.

For each of the calendar quarters between March 31, 2016 through June 30, 2017, Enfield received a quarterly distribution equal to an annual rate of 8.5% on the Issue Price payable in-kind in the form of additional Series B Preferred Units. For the quarter ended September 30, 2017 and each subsequent quarter, Enfield received or is entitled to receive a quarterly distribution, subject to certain adjustments, equal to an annual rate of 7.5% on the Issue Price payable in cash (the "Cash Distribution Component") plus an in-kind distribution equal to the greater of (A) 0.0025 Series B Preferred Units per Series B Preferred Unit and (B) an amount equal to (i) the excess, if any, of the distribution that would have been payable had the Series B Preferred Units converted into common units over the Cash Distribution Component, divided by (ii) the Issue Price.

Acquisitions, Organic Growth and Asset Sales in 2015 and 2016

- In January 2015, we acquired 100% of the voting equity interests of LPC Crude Oil Marketing LLC ("LPC"), which has crude oil gathering, transportation and marketing operations in the Permian Basin, for approximately $108.1 million.

- In March 2015, we acquired 100% of the voting equity interests in Coronado Midstream Holdings LLC ("Coronado"), which owns natural gas gathering and processing facilities in the Permian Basin, for approximately $600.3 million.

- In April 2015, we acquired VEX, located in the Eagle Ford Shale in South Texas, together with 100% of the voting equity interests (the "VEX interests") in certain entities, from Devon in a drop down transaction (the "VEX Drop Down") for $166.7 million in cash and approximately $9.0 million in common units. Additionally, we assumed $40.0 million in construction costs related to VEX.

- In October 2015, we acquired 100% of the voting equity interests in a subsidiary of Matador Resources Company ("Matador"), which has gathering and processing operations in the Delaware Basin, for approximately $141.3 million.

- Prior to November 2015, we co-owned the Deadwood natural gas processing plant with a subsidiary of Apache Corporation ("Apache"). In November 2015, we acquired Apache's 50% ownership interest in the Deadwood natural gas processing facility for approximately $40.1 million. We now own 100% of the Deadwood processing plant.

- In 2015, Acacia contributed the remaining 50% interest in Midstream Holdings to us in exchange for 68.2 million units of our limited partnership interestsin two separate drop down transactions, with 25% contributed in February 2015 and 25% contributed in May 2015 (the "EMH Drop Downs"). After giving effect to the EMH Drop Downs, we own 100% of Midstream Holdings.

- In January 2016, ENLK and ENLC acquired an 83.9% and 16.1% interest, respectively, in EnLink Oklahoma T.O. for aggregate consideration of approximately $1.4 billion. The EnLink Oklahoma T.O. assets serve gathering and processing needs in the growing STACK and CNOW plays in Central Oklahoma and are supported by long-term, fixed-fee contracts with acreage dedications that, at the time of acquisition, had a weighted-average term of approximately 15 years.

- In April 2016, we completed construction of the 100 MMcf/d Riptide processing plant in the Permian Basin.

- In August 2016, we formed the Delaware Basin JV with NGP to operate and expand our natural gas, natural gas liquids and crude oil midstream assets in the Delaware Basin. The Delaware Basin JV is owned 50.1% by us and 49.9% by NGP.

- In October 2016, we completed construction of the initial phase of the 60 MMcf/d Lobo II processing facilities.

- In November 2016, we formed the Cedar Cove JV with Kinder Morgan, Inc., which consists of gathering and compression assets in Blaine County, Oklahoma, located in the heart of the STACK play. The gathering system has a capacity of 25 MMcf/d with over 50,000 gross acres of dedications and ties into our existing Oklahoma assets. All gas gathered by the Cedar Cove JV is processed at our Central Oklahoma processing system. We hold a 30% ownership interest of the Cedar Cove JV, and Kinder Morgan, Inc. holds the remaining 70% ownership interest.

- In December 2016, we sold the North Texas Pipeline (the "NTPL"), a 140-mile natural gas transportation pipeline, for $84.6 million. We maintain capacity on the NTPL at competitive rates and at levels sufficient to support current and expected operations. As a result of the sale, we recorded a loss of $13.4 million for the year ended December 31, 2016.

Non-GAAP Financial Measures

We include the following non-GAAP financial measures: Adjusted earnings before interest, taxes, depreciation and amortization ("adjusted EBITDA"), distributable cash flow available to common unitholders ("distributable cash flow") and gross operating margin.

Adjusted EBITDA

We define adjusted EBITDA as net income (loss) plus interest expense, provision (benefit) for income taxes, depreciation and amortization expense, impairments, unit-based compensation, (gain) loss on non-cash derivatives, (gain) loss on disposition of assets, (gain) loss on extinguishment of debt, successful acquisition transaction costs, accretion expense associated with asset retirement obligations, reimbursed employee costs, non-cash rent, and distributions from unconsolidated affiliate investments, less payments under onerous performance obligations, non-controlling interest, income (loss) from unconsolidated affiliate investments and transferred interest adjusted EBITDA. Adjusted EBITDA is a primary metric used in our short-term incentive program for compensating employees. In addition, adjusted EBITDA is used as a supplemental liquidity and performance measure by our management and by external users of our financial statements, such as investors, commercial banks, research analysts and others, to assess:

- the financial performance of our assets without regard to financing methods, capital structure or historical cost basis;

- the ability of our assets to generate cash sufficient to pay interest costs, support our indebtedness and make cash distributions to our unitholders and our general partner;

- our operating performance and return on capital as compared to those of other companies in the midstream energy sector, without regard to financing methods or capital structure; and

- the viability of acquisitions and capital expenditure projects and the overall rates of return on alternative investment opportunities.

The GAAP measures most directly comparable to adjusted EBITDA are net income (loss) and net cash provided by operating activities. Adjusted EBITDA should not be considered an alternative to, or more meaningful than, net income (loss), operating income (loss), net cash provided by operating activities or any other measure of financial performance presented in accordance with GAAP. Adjusted EBITDA may not be comparable to similarly-titled measures of other companies because other entities may not calculate adjusted EBITDA in the same manner.

Adjusted EBITDA does not include interest expense, income taxes or depreciation and amortization expense. Because we have borrowed money to finance our operations, interest expense is a necessary element of our costs and our ability to generate cash available for distribution. Because we use capital assets, depreciation and amortization are also necessary elements of our costs. Therefore, any measures that exclude these elements have material limitations. To compensate for these limitations, we believe that it is important to consider net income (loss) and net cash provided by operating activities as determined under GAAP, as well as adjusted EBITDA, to evaluate our overall performance.

The following tables reconcile adjusted EBITDA to the most directly comparable GAAP measure for the periods indicated (in millions):

	Year Ended December 31,		
	2017	2016	2015
Reconciliation of net income (loss) to adjusted EBITDA			
Net income (loss)	$ 154.8	$ (573.3)	$ (1,378.2)
Interest expense, net of interest income	187.9	188.1	102.5
Depreciation and amortization	545.3	503.9	387.3
Impairments	17.1	566.3	1,563.4
(Income) loss from unconsolidated affiliate investments (1)	(9.6)	19.9	(20.4)
Distributions from unconsolidated affiliate investments (2)	13.5	25.0	42.7
Loss on disposition of assets	—	13.2	1.2
Gain on extinguishment of debt	(9.0)	—	—
Unit-based compensation	47.8	30.0	35.7
Income tax provision (benefit)	(24.0)	1.3	(0.5)
(Gain) loss on non-cash derivatives	(4.7)	20.1	7.7
Payments under onerous performance obligation offset to other current and long-term liabilities	(17.9)	(17.9)	(17.9)
Other (3)	4.6	6.9	11.3
Adjusted EBITDA before non-controlling interest	$ 905.8	$ 783.5	$ 734.8
Non-controlling interest share of adjusted EBITDA (4)	(33.0)	(8.9)	0.4
Transferred interest adjusted EBITDA (5)	—	—	(56.9)
Adjusted EBITDA, net to EnLink Midstream Partners, LP	$ 872.8	$ 774.6	$ 678.3

(1) Includes losses of $3.4 million and $20.1 million for the years ended December 31, 2017 and 2016, respectively, related to the sale of our HEP interests.

(2) Distributions for the year ended December 31, 2016 do not include $32.7 million of distributions received from HEP during the third quarter of 2016 attributable to the redemption of preferred units. The preferred units were issued to us by HEP during the second and third quarters of 2016 for contributions of $29.5 million and $3.2 million, respectively.

(3) Includes accretion expense associated with asset retirement obligations; reimbursed employee costs from Devon and LPC; successful acquisition transaction costs, which we do not consider in determining adjusted EBITDA because operating cash flows are not used to fund such costs; and non-cash rent, which relates to lease incentives pro-rated over the lease term.

(4) Non-controlling interest share of adjusted EBITDA includes ENLC’s 16.1% share of adjusted EBITDA from EnLink Oklahoma T.O., which was acquired in January 2016, NGP’s 49.9% share of adjusted EBITDA from the Delaware Basin JV, which was formed in August 2016, Marathon Petroleum’s 50% share of adjusted EBITDA from the Ascension JV, which began operations in April 2017, and other minor non-controlling interests.

(5) Represents recast E2, Midstream Holdings and VEX adjusted EBITDA prior to the date of the drop down of the respective assets or interests from ENLC and Devon.

Distributable Cash Flow

We define distributable cash flow as adjusted EBITDA (as defined above), net to the Partnership, less interest expense (excluding amortization of the EnLink Oklahoma T.O. acquisition installment payable discount), litigation settlement adjustment, adjustments for the redeemable non-controlling interest, interest rate swaps, current income taxes and other non-distributable cash flows, accrued cash distributions on Series B Preferred Units and Series C Preferred Units paid or expected to be paid, and maintenance capital expenditures, excluding maintenance capital expenditures that were contributed by other entities and relate to the non-controlling interest share of our consolidated entities. Distributable cash flow is used as a supplemental liquidity measure by our management and by external users of our financial statements, such as investors, commercial banks, research analysts and others, to assess the ability of our assets to generate cash sufficient to pay interest costs, support our indebtedness and make cash distributions to our common unitholders and our general partner.

Maintenance capital expenditures include capital expenditures made to replace partially or fully depreciated assets in order to maintain the existing operating capacity of the assets and to extend their useful lives. Examples of maintenance capital expenditures are expenditures to refurbish and replace pipelines, gathering assets, well connections, compression assets and processing assets up to their original operating capacity, to maintain pipeline and equipment reliability, integrity and safety and to address environmental laws and regulations.

The GAAP measure most directly comparable to distributable cash flow is net cash provided by operating activities. Distributable cash flow should not be considered an alternative to, or more meaningful than, net income (loss), operating income (loss), net cash provided by operating activities or any other measure of liquidity presented in accordance with GAAP. Distributable cash flow has important limitations because it excludes some items that affect net income (loss), operating income (loss) and net cash provided by operating activities. Distributable cash flow may not be comparable to similarly-titled measures of other companies because other entities may not calculate distributable cash flow in the same manner. To compensate for these limitations, we believe that it is important to consider net cash provided by operating activities determined under GAAP, as well as distributable cash flow, to evaluate our overall liquidity.

Reconciliation of net cash provided by operating activities to adjusted EBITDA and Distributable Cash Flow (in millions):

	Year Ended December 31,		
	2017	2016	2015
Net cash provided by operating activities	$ 706.5	$ 662.6	$ 645.6
Interest expense, net (1)	158.8	135.3	104.0
Current income tax expense	2.6	1.9	3.1
Distributions from unconsolidated affiliate investment in excess of earnings (2)	0.2	21.9	21.1
Other (3)	6.3	4.2	10.7
Changes in operating assets and liabilities which (provided) used cash:			
Accounts receivable, accrued revenues, inventories and other	213.2	107.7	(201.6)
Accounts payable, accrued gas and crude oil purchases and other (4)	(181.8)	(150.1)	151.9
Adjusted EBITDA before non-controlling interest	$ 905.8	$ 783.5	$ 734.8
Non-controlling interest share of adjusted EBITDA (5)	(33.0)	(8.9)	0.4
Transferred interest adjusted EBITDA (6)	—	—	(56.9)
Adjusted EBITDA, net to EnLink Midstream Partners, LP	$ 872.8	$ 774.6	$ 678.3
Interest expense, net of interest income	(187.9)	(188.1)	(102.5)
Amortization of EnLink Oklahoma T.O. installment payable discount included in interest expense (7)	26.4	52.3	—
Litigation settlement adjustment (8)	(18.1)	—	—
Non-cash adjustment for redeemable non-controlling interest	—	0.3	(1.8)
Interest rate swap (9)	—	0.4	(3.6)
Current taxes and other	(2.5)	(1.9)	(2.8)
Maintenance capital expenditures, net to EnLink Midstream Partners, LP (10)	(30.9)	(30.5)	(38.3)
Preferred unit accrued cash distributions (11)	(38.7)	—	—
Distributable cash flow	$ 621.1	$ 607.1	$ 529.3

(1) Net of amortization of debt issuance costs, discount and premium, and valuation adjustment for redeemable non-controlling interest included in interest expense but not included in net cash provided by operating activities.

(2) Distributions for the year ended December 31, 2016 do not include $32.7 million of distributions received from HEP during the third quarter of 2016 attributable to the redemption of preferred units. The preferred units were issued to us by HEP during the second and third quarters of 2016 for contributions of $29.5 million and $3.2 million, respectively.

(3) Includes successful acquisition transaction costs, which we do not consider in determining adjusted EBITDA because operating cash flows are not used to fund such costs, non-cash rent, which relates to lease incentives pro-rated over the lease term, gains and losses on settled interest rate swaps designated as hedges related to debt issuances, which are recorded in other comprehensive income (loss), and reimbursed employee costs from Devon and LPC, which are costs reimbursed to us by previous employers pursuant to acquisition or merger.

(4) Net of payments under onerous performance obligation offset to other current and long-term liabilities.

(5) Non-controlling interest share of adjusted EBITDA includes ENLC's 16.1% share of adjusted EBITDA from EnLink Oklahoma T.O., which was acquired in January 2016, NGP's 49.9% share of adjusted EBITDA from the Delaware Basin JV, which was formed in August 2016, Marathon Petroleum's 50% share of adjusted EBITDA from the Ascension JV, which began operations in April 2017, and other minor non-controlling interests.

(6) Represents recast E2, EMH and VEX adjusted EBITDA prior to the date of the drop down of the respective assets or interests from ENLC and Devon.

(7) Amortization of the EnLink Oklahoma T.O. installment payable discount is considered non-cash interest under our credit facility since the payment under the payable is consideration for the acquisition of the EnLink Oklahoma T.O. assets.

(8) Represents recoveries from litigation settlement for amounts not previously deducted from distributable cash flow. See "Item 8. Financial Statements—Note 14" for additional information.

(9) During the third quarter of 2016 and second quarter of 2015, we entered into interest rate swap arrangements to mitigate our exposure to interest rate movements prior to our note issuances. The gain on settlement of the interest rate swaps was considered excess proceeds for the note issuance and is therefore excluded from distributable cash flow.

(10) Excludes maintenance capital expenditures that were contributed by other entities and relate to the non-controlling interest share of our consolidated entities.

(11) Represents the cash distributions earned by the Series B Preferred Units of $32.0 million for the year ended December 31, 2017 and $6.7 million earned by the Series C Preferred Units for the year ended December 31, 2017. Cash distributions to be paid to holders of the Series B Preferred Units and Series C Preferred Units are not available to common unitholders. See "Item 8. Financial Statements—Note 8" for additional information.

Gross Operating Margin

We define gross operating margin as revenues less cost of sales. We present gross operating margin by segment in “Results of Operations.” We disclose gross operating margin in addition to total revenue because it is the primary performance measure used by our management. We believe gross operating margin is an important measure because, in general, our business is to gather, process, transport or market natural gas, NGLs, crude oil and condensate for a fee or to purchase and resell natural gas, NGLs, condensate and crude oil for a margin. Operating expense is a separate measure used by our management to evaluate operating performance of field operations. Direct labor and supervision, property insurance, property taxes, repair and maintenance, utilities and contract services comprise the most significant portion of our operating expenses. We do not deduct operating expenses from total revenue in calculating gross operating margin because these expenses are largely independent of the volumes we transport or process and fluctuate depending on the activities performed during a specific period. The GAAP measure most directly comparable to gross operating margin is operating income (loss). Gross operating margin should not be considered an alternative to, or more meaningful than, operating income (loss) as determined in accordance with GAAP. Gross operating margin has important limitations because it excludes all operating costs that affect operating income (loss) except cost of sales. Our gross operating margin may not be comparable to similarly-titled measures of other companies because other entities may not calculate these amounts in the same manner.

The following table provides a reconciliation of operating income (loss) to gross operating margin (in millions):

	Year Ended December 31,		
	2017	2016	2015
Operating income (loss)	$ 299.5	$ (364.3)	$ (1,297.4)
Add (deduct):			
Operating expenses	418.7	398.5	419.9
General and administrative expenses	123.5	119.3	132.4
Loss on disposition of assets	—	13.2	1.2
Depreciation and amortization	545.3	503.9	387.3
Impairments	17.1	566.3	1,563.4
Gain on litigation settlement	(26.0)	—	—
Gross operating margin	$ 1,378.1	$ 1,236.9	$ 1,206.8

Results of Operations

The table below sets forth certain financial and operating data for the periods indicated. We manage our operations by focusing on gross operating margin, which we define as revenue less cost of sales as reflected in the table below (in millions, except volumes):

	Year Ended December 31,		
	2017	2016	2015
Texas Segment			
Revenues	$ 1,365.9	$ 1,068.3	$ 1,000.2
Cost of sales	(772.3)	(483.4)	(412.2)
Total gross operating margin	$ 593.6	$ 584.9	$ 588.0
Louisiana Segment			
Revenues	$ 2,931.6	$ 2,001.5	$ 1,840.3
Cost of sales	(2,618.1)	(1,729.0)	(1,567.6)
Total gross operating margin	$ 313.5	$ 272.5	$ 272.7
Oklahoma Segment			
Revenues	$ 874.8	$ 437.0	$ 187.0
Cost of sales	(522.9)	(184.9)	(17.9)
Total gross operating margin	$ 351.9	$ 252.1	$ 169.1
Crude and Condensate Segment			
Revenues	$ 1,453.6	$ 1,176.5	$ 1,498.2
Cost of sales	(1,330.3)	(1,038.0)	(1,330.6)
Total gross operating margin	$ 123.3	$ 138.5	$ 167.6
Corporate			
Revenues	$ (886.3)	$ (430.9)	$ (73.6)
Cost of sales	882.1	419.8	83.0
Total gross operating margin	$ (4.2)	$ (11.1)	$ 9.4
Total			
Revenues	$ 5,739.6	$ 4,252.4	$ 4,452.1
Cost of sales	(4,361.5)	(3,015.5)	(3,245.3)
Total gross operating margin	$ 1,378.1	$ 1,236.9	$ 1,206.8
Midstream Volumes:			
Texas			
Gathering and Transportation (MMBtu/d)	2,262,900	2,622,600	2,849,600
Processing (MMBtu/d)	1,184,400	1,173,100	1,222,700
Louisiana			
Gathering and Transportation (MMBtu/d)	1,995,800	1,676,600	1,468,300
Processing (MMBtu/d)	453,300	490,300	506,100
NGL Fractionation (Gals/d)	5,772,800	5,197,100	5,771,500
Oklahoma			
Gathering and Transportation (MMBtu/d)	829,300	626,300	428,600
Processing (MMBtu/d)	810,300	574,900	359,600
Crude and Condensate			
Crude Oil Handling (Bbls/d)	108,200	94,000	131,500
Brine Disposal (Bbls/d)	4,200	3,600	3,900

Year Ended December 31, 2017 Compared to Year Ended December 31, 2016

Gross Operating Margin. Gross operating margin was $1,378.1 million for the year ended December 31, 2017 compared to $1,236.9 million for the year ended December 31, 2016, an increase of $141.2 million, or 11.4%, due to the following:

- *Texas Segment.* Gross operating margin in the Texas segment increased $8.7 million, which was primarily due to a $25.9 million increase in gross operating margin due to higher volumes from our expansion in the Permian Basin. This increase was partially offset by a $17.2 million decrease in gross operating margin from our North Texas processing, gathering and transmission assets due to volume declines across our North Texas system, including an $11.5 million decrease due to the sale of the NTPL assets in December 2016. Although we experienced volume declines for certain of our Barnett-Shale assets, the impact of these volume declines on gross operating margin was offset by an increase in revenue earned from minimum volume commitments ("MVC" or "MVCs") (as discussed in more detail below) under our contracts with Devon. For the year ended December 31, 2017 the shortfall revenue from Devon-related MVCs was $59.2 million compared to $26.4 million for the year ended December 31, 2016.

- *Louisiana Segment.* Gross operating margin in the Louisiana segment increased $41.0 million, which was primarily due to a $34.2 million increase in gross operating margin from our NGL transmission and fractionation assets and a $6.8 million increase in gross operating margin from our Louisiana gathering and transmission assets. The increase from our NGL business was primarily due to additional NGL volumes fractionated, including volumes received from our Oklahoma and Permian Basin assets, together with a $9.3 million gross operating margin contribution from fees earned on our Ascension JV assets, which commenced operations in April 2017. The increase from our transmission assets was primarily due to volume increases on our Louisiana Intrastate Gas and Gulf Coast pipeline systems.

- *Oklahoma Segment.* Gross operating margin in the Oklahoma segment increased $99.8 million, which was primarily driven by a $104.8 million increase from our Central Oklahoma assets as a result of higher volumes due to continued producer development in Oklahoma. This increase was partially offset by a $5.1 million decrease in gross operating margin from our Northridge gathering and processing assets due to price and volume reductions under a third-party contract.

- *Crude and Condensate Segment.* Gross operating margin in the Crude and Condensate segment decreased $15.2 million, which was primarily due to a $12.8 million decrease as a result of condensate stabilization volume declines and transportation rate decreases on our ORV assets and a decrease of $8.4 million as a result of volume declines in our Midland Basin trucking business. The volume and rate declines throughout our Crude and Condensate segment were primarily attributable to increased competition due to lower crude prices. These declines were partially offset by a $4.8 million increase due to the Greater Chickadee gathering system, which became fully operational in the first quarter of 2017.

- *Corporate Segment.* Gross operating margin in the Corporate segment increased $6.9 million, which was due to the changes in fair value of our commodity swaps between periods. For the year ended December 31, 2017, there were unrealized gains of $4.7 million, offset by realized losses of $8.9 million. For the year ended December 31, 2016, there were unrealized losses of $20.1 million, partially offset by realized gains of $9.0 million.

Certain gathering and processing agreements in our Texas, Oklahoma and Crude and Condensate segments provide for quarterly or annual MVCs, including MVCs from Devon from certain of our Barnett Shale assets in North Texas and our Cana plant in Oklahoma. Under these agreements, our customers agree to ship and/or process a minimum volume of production on our systems over an agreed time period. If a customer under such an agreement fails to meet its MVC for a specified period, the customer is obligated to pay a contractually-determined fee based upon the shortfall between actual production volumes and the MVC for that period. Some of these agreements also contain make-up right provisions that allow a customer to utilize gathering or processing fees in excess of the MVC in subsequent periods to offset shortfall amounts in previous periods. We record revenue under MVC contracts during periods of shortfall when it is known that the customer cannot, or will not, make up the deficiency in subsequent periods.

Revenue recorded for the shortfall between actual production volumes and the MVC were as follows (in millions):

	Texas	Oklahoma	Crude and Condensate	Total
Year Ended December 31, 2017				
Midstream services	$ 0.8	$ 16.1	$ —	$ 16.9
Midstream services—related parties	59.2	13.8	8.9	81.9
Total	$ 60.0	$ 29.9	$ 8.9	$ 98.8
Year Ended December 31, 2016				
Midstream services	$ 1.9	$ 9.5	$ —	$ 11.4
Midstream services—related parties	26.4	10.8	9.0	46.2
Total	$ 28.3	$ 20.3	$ 9.0	$ 57.6

On January 1, 2019, certain Devon MVC agreements in the Texas and Oklahoma segments will expire. These expiring MVC agreements generated $72.6 million in shortfall revenue for the year ended December 31, 2017. In 2018, expiring MVC agreements in North Texas and Oklahoma are projected to generate approximately $80-90 million in shortfall revenue. For additional information, refer to "Item 1. Business—Our Contractual Relationship with Devon."

Operating Expenses. Operating expenses were $418.7 million for the year ended December 31, 2017 compared to $398.5 million for the year ended December 31, 2016, an increase of $20.2 million, or 5.1%. The primary contributors to the total increase by segment were as follows (in millions):

	Year Ended December 31,		Change	
	2017	2016	$	%
Texas Segment	$ 172.7	$ 168.5	$ 4.2	2.5 %
Louisiana Segment	101.3	96.6	4.7	4.9 %
Oklahoma Segment	64.6	52.1	12.5	24.0 %
Crude and Condensate Segment	80.1	81.3	(1.2)	(1.5)%
Total	$ 418.7	$ 398.5	$ 20.2	5.1 %

- *Louisiana Segment.* Operating expenses in the Louisiana segment increased $4.7 million primarily due to increases in materials and supplies expense of $2.7 million, labor and benefits expense of $1.7 million, utilities expense of $1.3 million and regulatory expense of $1.0 million as a result of increased activity on our Louisiana systems, partially offset by reduced compressor rental expenses of $2.2 million resulting from the purchase of compressors.

- *Oklahoma Segment.* Operating expenses in the Oklahoma segment increased $12.5 million primarily due to increased property insurance costs of $5.4 million, increased labor and benefits expense of $3.5 million attributable to higher headcount and to increased materials and supplies expense of $3.7 million as a result of expanded operations.

General and Administrative Expenses. General and administrative expenses were $123.5 million for the year ended December 31, 2017 compared to $119.3 million for the year ended December 31, 2016, an increase of $4.2 million, or 3.5%. The primary contributors to the increase were as follows:

- Unit-based compensation expense increased $13.7 million due to bonuses paid in the form of units, which vested immediately in March 2017, and the accrual of annual bonuses for 2017;
- Transaction costs decreased $3.8 million and transition service fees decreased $1.5 million due to the costs incurred during 2016 related to the EnLink Oklahoma T.O. acquisition, with no transaction or transition costs incurred for the year ended December 31, 2017; and
- Wages and salaries expense decreased $3.6 million due to severance payments made during 2016 and a decrease in bonus expenses for the year ended December 31, 2017.

Loss on Disposition of Assets. For the year ended December 31, 2016, we recorded a loss on disposition of assets of $13.2 million, which was primarily attributable to a $13.4 million loss on sale of the NTPL.

Depreciation and Amortization. Depreciation and amortization expenses were $545.3 million for the year ended December 31, 2017 compared to $503.9 million for the year ended December 31, 2016, an increase of $41.4 million, or 8.2%. Of this increase, $18.8 million was attributable to the plant expansion of our Permian Basin gathering and processing assets; $15.8 million was attributable to the expansion of our Central Oklahoma assets; $4.7 million was attributable to the Greater Chickadee gathering system; $3.4 million was attributable to the acceleration of depreciation for some North Texas compressor stations decommissioned during 2017; and $2.6 million was attributable to the Ascension JV assets. These increases were partially offset by a $4.3 million decrease in depreciation expense related to the sale of NTPL in December 2016.

Impairments. Impairment expense was $17.1 million for the year ended December 31, 2017 compared to impairment expense of $566.3 million for the year ended December 31, 2016, a decrease of $549.2 million, or 97.0%. In the first quarter of 2016, we recognized an impairment on goodwill of $566.3 million related to our Texas and Crude and Condensate segments. For the year ended December 31, 2017, we recognized property and equipment impairments of $17.1 million, which related to the carrying values of rights-of-way that we are no longer using and an abandoned brine disposal well.

Gain on Litigation Settlement. We recognized a gain on litigation settlement of $26.0 million for the year ended December 31, 2017. See "Item 8. Financial Statements—Note 14" for additional information.

Gain on Extinguishment of Debt. We recognized a gain on extinguishment of debt of $9.0 million for the year ended December 31, 2017 due to the redemption of the 2022 Notes. See "Item 8. Financial Statements—Note 6" for additional information.

Interest Expense. Interest expense was $187.9 million for the year ended December 31, 2017 compared to $188.1 million for the year ended December 31, 2016, a decrease of $0.2 million, or 0.1%. Net interest expense consisted of the following (in millions):

	Year Ended December 31,	
	2017	2016
Senior notes	$ 155.0	$ 131.1
Credit facility	9.5	11.7
Capitalized interest	(6.3)	(7.2)
Amortization of debt issue costs and net discount	29.1	53.1
Cash settlements on interest rate swaps	—	(0.4)
Mandatory redeemable non-controlling interest	—	0.3
Other	0.6	(0.5)
Total interest expense, net of interest income	$ 187.9	$ 188.1

Income (loss) from Unconsolidated Affiliate Investments. Income from unconsolidated affiliate investments was $9.6 million for the year ended December 31, 2017 compared to a loss of $19.9 million for the year ended December 31, 2016, an increase of $29.5 million. The increase was primarily due to a $23.3 million loss from our investment in HEP for the year ended December 31, 2016 compared to a $3.4 million loss from the sale of HEP for the year ended December 31, 2017. The loss from our investment in HEP for the year ended December 31, 2016 was primarily due to the $20.1 million impairment of our investment in HEP in the fourth quarter of 2016 to reduce the carrying value of our investment to the expected sale price. In addition, we generated increased income of $9.2 million from our GCF investment for the year ended December 31, 2017 compared to the year ended December 31, 2016 due to higher fractionation revenues and lower operating expenses.

Income Tax Benefit (Expense). Income tax benefit was $24.0 million for the year ended December 31, 2017 compared to income tax expense of $1.3 million for the year ended December 31, 2016, a decrease of tax expense of $25.3 million primarily due to a change in tax rates. On December 22, 2017, the Tax Cuts and Jobs Act was signed into legislation and resulted in a change in the federal statutory corporate rate from 35% to 21%, effective January 1, 2018. We recognized a tax benefit of $24.9 million during the fourth quarter of 2017 due to the re-measurement of our deferred tax liabilities to reflect the reduction in the federal statutory corporate rate.

Year Ended December 31, 2016 Compared to Year Ended December 31, 2015

Gross Operating Margin. Gross operating margin was $1,236.9 million for the year ended December 31, 2016 compared to $1,206.8 million for the year ended December 31, 2015, an increase of $30.1 million, or 2.5%, due to the following:

- *Texas Segment.* Gross operating margin in the Texas segment decreased $3.1 million, which was primarily due to a $34.1 million decrease in gross operating margin as a result of volume declines and expirations of certain higher margin contracts for our North Texas processing, gathering, and transportation assets. The gross operating margin decline due to volumes included MVC revenue from our contracts with Devon of $26.4 million for the year ended December 31, 2016 as compared to $3.8 million for the year ended December 31, 2015. This decrease from our North Texas assets was partially offset by gross operating margin contributions totaling $20.5 million from 2015 acquisitions on the MEGA system. In addition, volume growth in the MEGA system resulted in an additional $10.7 million increase in gross operating margin between periods.

- *Louisiana Segment.* Gross operating margin in the Louisiana segment decreased $0.2 million. The Louisiana segment realized a 1.0% decrease in gross operating margin from its NGL business as a result of declines in pipeline throughput and fractionation volumes, substantially offset by an increase in gross operating margin from the Louisiana gas business.

- *Oklahoma Segment.* Gross operating margin in the Oklahoma segment increased $83.0 million, which was driven by a gross operating margin contribution of $82.0 million from the EnLink Oklahoma T.O. assets acquired in January 2016. In addition, our gross operating margin from our Cana gathering and processing assets increased by $5.8 million between periods primarily due to increased volumes from Devon, including MVC revenue from Devon of $10.8 million for the year ended December 31, 2016 compared to $20.1 million for the year ended December 31, 2015. This increase was partially offset by a decline in gross operating margin of $5.4 million at our Northridge gathering and processing assets as a result of a decline in volumes and a rate reduction on a third-party contract.

- *Crude and Condensate Segment.* Gross operating margin in the Crude and Condensate segment decreased $29.1 million. A decrease of $24.7 million resulted from the termination of a customer contract during the second quarter of 2015 and included a $10.3 million early termination payment from the customer in 2015. The remaining decrease was primarily the result of volume declines throughout the Crude and Condensate segment.

- *Corporate Segment.* The Corporate segment included a loss from derivative activity of $11.1 million for the year ended December 31, 2016 compared to a gain of $9.4 million for the year ended December 31, 2015 related to the changes in fair value of our commodity swaps between periods. For the year ended December 31, 2016, there were realized gains of $9.0 million offset by unrealized losses of $20.1 million. For the year ended December 31, 2015, there were realized gains of $17.1 million partially offset by unrealized losses of $7.7 million.

Revenue recorded for the shortfall between actual production volumes and the MVC were as follows (in millions):

	Texas	Oklahoma	Crude and Condensate	Total
Year Ended December 31, 2016				
Midstream services	$ 1.9	$ 9.5	$ —	$ 11.4
Midstream services—related parties	26.4	10.8	9.0	46.2
Total	$ 28.3	$ 20.3	$ 9.0	$ 57.6
Year Ended December 31, 2015				
Midstream services	$ 0.5	$ —	$ —	$ 0.5
Midstream services—related parties	3.8	20.1	0.5	24.4
Total	$ 4.3	$ 20.1	$ 0.5	$ 24.9

Operating Expenses. Operating expenses were $398.5 million for the year ended December 31, 2016 compared to $419.9 million for the year ended December 31, 2015, a decrease of $21.4 million, or 5.1%. The primary contributors to the total decrease by segment were as follows (in millions):

	Year Ended December 31,		Change	
	2016	2015	$	%
Texas Segment	$ 168.5	$ 181.8	$ (13.3)	(7.3)%
Louisiana Segment	96.6	105.9	(9.3)	(8.8)%
Oklahoma Segment	52.1	30.3	21.8	71.9 %
Crude and Condensate Segment	81.3	101.9	(20.6)	(20.2)%
Total	$ 398.5	$ 419.9	$ (21.4)	(5.1)%

- *Texas Segment.* Operating expenses in the Texas segment decreased $13.3 million primarily due to lower operating costs of $18.3 million resulting from overall cost reduction measures and lower rental expense on compressors. These decreases were partially offset by a $8.0 million increase in operating expenses attributable to the acquisitions in the MEGA system.

- *Louisiana Segment.* Operating expenses in the Louisiana segment decreased $9.3 million primarily due to overall cost reduction measures, including cost savings from materials and supplies, construction fees and services and labor. In addition, rental expense decreased $1.0 million due to rental equipment that was returned in the first quarter of 2016.

- *Oklahoma Segment.* Operating expenses in the Oklahoma segment increased $21.8 million primarily due to the EnLink Oklahoma T.O. acquisition in January 2016.

- *Crude and Condensate Segment.* Operating expenses in the Crude and Condensate segment decreased $20.6 million primarily due to decreased trucking volumes, which decreased labor, fuel and contractor costs, in addition to overall cost reduction measures.

General and Administrative Expenses. General and administrative expenses were $119.3 million for the year ended December 31, 2016 compared to $132.4 million for the year ended December 31, 2015, a decrease of $13.1 million, or 9.9%. The primary contributors to the decrease are as follows:

- Unit-based compensation expense decreased $7.3 million due primarily to bonuses being paid in the form of units that immediately vested in March 2015;
- Wages and salaries decreased $2.9 million due to a decrease in bonus expense;
- Software consulting fees decreased $2.0 million due to completed implementation of new software;
- Bad debt expense decreased $2.1 million;
- Transition service fees related to acquisitions decreased $1.0 million;
- Transaction costs related to acquisitions decreased $1.3 million;
- Travel and training expense decreased $1.0 million; and
- Rent expense increased $4.9 million related to new office leases that commenced during 2016.

Loss on Disposition of Assets. Loss on disposition of assets was $13.2 million for the year ended December 31, 2016 compared to a loss on disposition of assets of $1.2 million for the year ended December 31, 2015. The loss on disposition of assets for the year ended December 31, 2016 was primarily attributable to a $13.4 million loss on sale of the NTPL. The loss on disposition of assets for the year ended December 31, 2015 related to the retirement of a compressor due to fire damage.

Depreciation and Amortization. Depreciation and amortization expenses were $503.9 million for the year ended December 31, 2016 compared to $387.3 million for the year ended December 31, 2015, an increase of $116.6 million, or 30.1%. Of this increase, $88.6 million was attributable to the acquisition of the EnLink Oklahoma T.O. assets; $11.5 million was attributable to additional assets on the MEGA system; and $7.4 million was attributable to the Lobo plants. These increases were partially offset by a $14.4 million decrease in amortization attributable to the impairment of ORV intangible assets in the third quarter of 2015. The remaining increase in depreciation and amortization expense was primarily attributable to assets placed in service.

Impairments. Impairment expense was $566.3 million for the year ended December 31, 2016 compared to impairment expense of $1,563.4 million for the year ended December 31, 2015, a decrease of $997.1 million, or 63.8%. In the first quarter of 2016, we recognized an impairment on goodwill of $566.3 million related to our Texas and Crude and Condensate segments. For the year ended December 31, 2015, we recognized an impairment on goodwill of $1,328.2 million related to our Louisiana, Texas and Crude and Condensate segments and an impairment on intangible assets of $223.1 million in our Crude and Condensate segment. For the year ended December 31, 2015, we also recognized an impairment on property and equipment of $12.1 million primarily related to costs associated with the cancellation of various projects. For more information, see the “Critical Accounting Policies” section below.

Interest Expense. Interest expense was $188.1 million for the year ended December 31, 2016 compared to $102.5 million for the year ended December 31, 2015, an increase of $85.6 million, or 83.5%. Net interest expense consisted of the following (in millions):

	Year Ended December 31,	
	2016	2015
Senior notes	$ 131.1	$ 106.0
Credit facility	11.7	7.9
Capitalized interest	(7.2)	(7.7)
Amortization of debt issue costs and net discount	53.1	0.2
Cash settlements on interest rate swap	(0.4)	(3.6)
Redeemable non-controlling interest	0.3	(1.8)
Other	(0.5)	1.5
Total interest expense, net of interest income	$ 188.1	$ 102.5

The increase in interest expense of $85.6 million was primarily due to an increase of $52.3 million attributable to the non-cash amortization of the discount related to the EnLink Oklahoma T.O. acquisition installment payments in 2016 and an increase of $25.1 million attributable to the issuance of $900.0 million aggregate principal amount of unsecured senior notes in May 2015 and the issuance of $500.0 million in aggregate principal amount of unsecured senior notes in July 2016.

Income (loss) from Unconsolidated Affiliate Investments. Loss from unconsolidated affiliate investments was $19.9 million for the year ended December 31, 2016 compared to income of $20.4 million for the year ended December 31, 2015, a decrease of $40.3 million. This decrease was primarily due to a $23.3 million loss from our investment in HEP for the year ended December 31, 2016 compared to $7.4 million in income for the year ended December 31, 2015. The loss from our investment in HEP for the year ended December 31, 2016 was primarily due to the $20.1 million impairment of our investment in HEP in the fourth quarter of 2016 to reduce the carrying value of our investment to its expected sales price. In December 2016, we entered into an agreement to sell our ownership interest in HEP, and the sale closed in the first quarter of 2017. In addition, income from our investment in GCF also decreased $9.2 million due to lower revenues as a result of lower pipeline and fractionator feed volumes, together with increased operating costs for major scheduled fractionator maintenance during the first quarter of 2016.

Critical Accounting Policies

The selection and application of accounting policies is an important process that has developed as our business activities have evolved and as the accounting rules have developed. Accounting rules generally do not involve a selection among alternatives, but involve an implementation and interpretation of existing rules and the use of judgment to the specific set of circumstances existing in our business. Compliance with the rules involves reducing a number of very subjective judgments to a quantifiable accounting entry or valuation. We make every effort to properly comply with all applicable rules on or before their adoption, and we believe the proper implementation and consistent application of the accounting rules is critical.

Our critical accounting policies are discussed below. See “Item 8. Financial Statements and Supplementary Data—Note 2” for further details on our accounting policies.

Revenue Recognition. In May 2014, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") 2014-09, *Revenue from Contracts with Customers* ("ASU 2014-09"), which established Accounting Standards Codification ("ASC") Topic 606, Revenue from Contracts with Customers ("ASC 606"). ASC 606 will replace existing revenue recognition requirements in Generally Accepted Accounting Principles ("GAAP") and will require entities to recognize revenue at an amount that reflects the consideration to which they expect to be entitled in exchange for transferring goods or services to a customer. ASC 606 will also require significantly expanded disclosures containing qualitative and quantitative information regarding the nature, amount, timing and uncertainty of revenue and cash flows arising from contracts with customers. In May 2016, the FASB issued ASU 2016-12, *Revenue from Contracts with Customers (Topic 606): Narrow-Scope Improvements and Practical Expedients* ("ASU 2016-12"), which updated ASU 2014-09. ASU 2016-12 clarifies certain core recognition principles, including collectability, sales tax presentation, noncash consideration, contract modifications and completed contracts at transition and disclosures no longer required if the full retrospective transition method is adopted. ASU 2014-09 and ASU 2016-12 are effective for annual reporting periods beginning after December 15, 2017, including interim periods within those annual periods, and are to be applied using the modified retrospective or full retrospective transition methods, with early application permitted for annual reporting periods beginning after December 15, 2016. We will adopt ASC 606 using the modified retrospective method for annual and interim reporting periods beginning January 1, 2018.

We have aggregated and reviewed our contracts that are within the scope of ASC 606. Based on our evaluation to date, we do not anticipate the adoption of ASC 606 will have a material impact on our results of operations, financial condition or cash flows. However, ASC 606 will affect how certain transactions are recorded in the financial statements. For each contract with a customer, we will need to identify our performance obligations, of which the identification includes careful evaluation of when control and the economic benefits of the commodities transfer to us. The evaluation of control will change the way we account for certain transactions, specifically those in which there is both a commodity purchase component and a service component. For contracts where control of commodities transfers to us before we perform our services, we generally have no performance obligation for our services, and accordingly, we will not consider these revenue-generating contracts. Based on that determination, all fees or fee-equivalent deductions stated in such contracts would reduce the cost to purchase commodities. Alternatively, for contracts where control of commodities transfers to us after we perform our services, we have performance obligations for our services. Accordingly, we will consider the satisfaction of these performance obligations as revenue-generating and recognize these fees as midstream service revenues at the time we satisfy our performance obligations. For contracts where control of commodities never transfers to us and we simply earn a fee for our services, we will recognize these fees as midstream services revenues at the time we satisfy our performance obligations. Based on our review of our performance obligations in our contracts with customers, we will change the statement of operations classification for certain transactions from revenue to cost of sales or from cost of sales to revenue. We estimate that the reclassification of revenues and costs will result in a net decrease in revenue of approximately 6-10%, although this estimate is based on historical information and could change based on commodity prices going forward. This reclassification of revenues and costs will have no effect on operating income and gross operating margin.

Our performance obligations represent promises to transfer a series of distinct goods or services that are satisfied over time and that are substantially the same to the customer. As permitted by ASC 606, we will utilize the practical expedient that allows an entity to recognize revenue in the amount to which the entity has a right to invoice, if an entity has a right to consideration from a customer in an amount that corresponds directly with the value to the customer of the entity's performance completed to date. Accordingly, we will continue to recognize revenue at the time commodities are delivered or services are performed, so ASC 606 will not significantly affect the timing of revenue and expense recognition on our statements of operations.

Impairment of Long-Lived Assets. In accordance with ASC 360, *Property, Plant and Equipment*, we evaluate long-lived assets, including related intangibles, of identifiable business activities for potential impairment whenever events or changes in circumstances indicate that their carrying value may not be recoverable. The carrying amount of a long-lived asset is not recoverable when it exceeds the undiscounted sum of the future cash flows expected to result from the use and eventual disposition of the asset. Estimates of expected future cash flows represent management's best estimate based on reasonable and supportable assumptions. When the carrying amount of a long-lived asset is not recoverable, an impairment loss is recognized equal to the excess of the asset's carrying value over its fair value.

When determining whether impairment of our long-lived assets has occurred, we must estimate the undiscounted cash flows attributable to the asset. Our estimate of cash flows is based on assumptions regarding:

- the future fee-based rate of new business or contract renewals;
- the purchase and resale margins on natural gas, NGLs, crude oil and condensate;
- the volume of natural gas, NGLs, crude oil and condensate available to the asset;
- markets available to the asset;
- operating expenses; and
- future natural gas, NGLs, crude oil and condensate prices.

The amount of availability of natural gas, NGLs, crude oil and condensate to an asset is sometimes based on assumptions regarding future drilling activity, which may be dependent in part on natural gas, NGL, crude oil and condensate prices. Projections of natural gas, NGL, crude oil and condensate volumes and future commodity prices are inherently subjective and contingent upon a number of variable factors, including but not limited to:

- changes in general economic conditions in regions in which our markets are located;
- the availability and prices of natural gas, NGLs, crude oil and condensate supply;
- our ability to negotiate favorable sales agreements;
- the risks that natural gas, NGLs, crude oil and condensate exploration and production activities will not occur or be successful;
- our dependence on certain significant customers, producers and transporters of natural gas, NGLs, crude oil and condensate; and
- competition from other midstream companies, including major energy companies.

Any significant variance in any of the above assumptions or factors could materially affect our cash flows, which could require us to record an impairment of an asset.

For 2016 and 2015, we reviewed our various assets groups for impairment due to the triggering events described in the goodwill impairment analysis below.We utilized Level 3 fair value measurements in our impairment analysis, which included discounted cash flow assumptions by management consistent with those utilized in our goodwill impairment analysis. During 2016, the undiscounted cash flows of our assets exceeded their carrying values, and no impairment was recorded. During 2015, the undiscounted cash flows related to one of our asset groups in the Crude and Condensate segment were not in excess of its related carrying value. We estimated the fair value of this reporting unit and determined the fair values of certain intangible assets were not in excess of their carrying values. This resulted in a $223.1 million impairment of intangible assets in our Crude and Condensate segment, and this non-cash impairment charge was included as an impairment loss on the consolidated statement of operations for the year ended December 31, 2015.

For the year ended December 31, 2017, we recognized impairments on property and equipment of $17.1 million, which related to the carrying values of rights-of-way that we are no longer using and an abandoned brine disposal well. For the year ended December 31, 2015, we recognized a $12.1 million impairment on property and equipment, primarily related to costs associated with the cancellation of various capital projects in our Texas, Louisiana, and Crude and Condensate segments.

Impairment of Goodwill. Goodwill is the cost of an acquisition less the fair value of the net identifiable assets of the acquired business.We evaluate goodwill for impairment annually as of October 31 and whenever events or changes in circumstances indicate it is more likely than not that the fair value of a reporting unit is less than its carrying amount. We first assess qualitative factors to evaluate whether it is more likely than not that the fair value of a reporting unit is less than its carrying amount as the basis for determining whether it is necessary to perform a goodwill impairment test. We may elect to perform a goodwill impairment test without completing a qualitative assessment.

We perform our goodwill assessments at the reporting unit level for all reporting units. We use a discounted cash flow analysis to perform the assessments. Key assumptions in the analysis include the use of an appropriate discount rate, terminal year multiples and estimated future cash flows, including volume and price forecasts and estimated operating and general and administrative costs. In estimating cash flows, we incorporate current and historical market and financial information, among other factors. Impairment determinations involve significant assumptions and judgments, and differing assumptions regarding any of these inputs could have a significant effect on the various valuations. If actual results are not consistent with our assumptions and estimates, or our assumptions and estimates change due to new information, we may be exposed to goodwill impairment charges, which would be recognized in the period in which the carrying value exceeds fair value.

Prior to January 2017, if a goodwill impairment test was elected or required, we performed a two-step goodwill impairment test. The first step involved comparing the fair value of the reporting unit to its carrying amount. If the carrying amount of a reporting unit exceeded its fair value, the second step of the process involved comparing the implied fair value to the carrying value of the goodwill for that reporting unit. If the carrying value of the goodwill of a reporting unit exceeded the implied fair value of that goodwill, the excess of the carrying value over the implied fair value was recognized as an impairment loss.

Effective January 2017, we elected to early adopt ASU 2017-04, *Intangibles—Goodwill and Other (Topic 350)— Simplifying the Test for Goodwill Impairment*, which simplified the accounting for goodwill impairments by eliminating the requirement to compare the implied fair value of goodwill with its carrying amount as part of step two of the goodwill impairment test referenced in ASC 350, *Intangibles—Goodwill and Other*. As a result, an entity should perform its annual or interim goodwill impairment test by comparing the fair value of a reporting unit with its carrying amount. An impairment charge should be recognized for the amount by which the carrying amount exceeds the reporting unit's fair value. However, the impairment loss recognized should not exceed the total amount of goodwill allocated to that reporting unit. Therefore, our annual impairment test as of October 31, 2017 was performed according to ASU 2017-04.

During the third quarter of 2015, we determined that sustained weakness in the overall energy sector, driven by low commodity prices together with a decline in our unit price, caused a change in circumstances warranting an interim impairment test. We also performed our annual impairment analysis during the fourth quarter of 2015. Although our established annual effective date for this goodwill analysis is October 31, we updated the effective date for this impairment analysis for the 2015 annual period to December 31, 2015 due to continued declines in commodity prices and our unit price during the fourth quarter of 2015.

Using the fair value approaches described above, in step one of the goodwill impairment test, we determined that the estimated fair values of our Louisiana, Texas and Crude and Condensate reporting units were less than their carrying amounts, primarily related to commodity prices, volume forecasts and discount rates. Based on that determination, we performed the second step of the goodwill impairment test by measuring the amount of impairment loss and allocating the estimated fair value of the reporting unit among all of the assets and liabilities of the reporting unit as if the reporting unit had been acquired in a business combination. Based on this analysis, a goodwill impairment loss for our Louisiana, Texas, and Crude and Condensate reporting units in the amount of $1,328.2 million was recognized for the year ended December 31, 2015 and is included as an impairment loss in the consolidated statement of operations.

During February 2016, we determined that continued further weakness in the overall energy sector, driven by low commodity prices together with a further decline in our unit price subsequent to year-end, caused a change in circumstances warranting an interim impairment test. Based on these triggering events, we performed a goodwill impairment analysis in the first quarter of 2016 on all reporting units. Based on this analysis, a goodwill impairment loss for our Texas and Crude and Condensate reporting units in the amount of $566.3 million was recognized in the first quarter of 2016 and is included as an impairment loss in the consolidated statement of operations for the year ended December 31, 2016.

For each of the aforementioned impairment testing periods during 2015 and 2016, we concluded that the fair value of our Oklahoma reporting unit exceeded its carrying value, and the amount of goodwill disclosed on the consolidated balance sheet associated with this reporting unit was recoverable. Therefore, no goodwill impairment was identified or recorded for this reporting unit as a result of our goodwill impairment analyses.

During our annual impairment tests for 2016 and 2017 performed as of October 31 of each year, we determined that no further impairments were required for the years ended December 31, 2017 and 2016.

Liquidity and Capital Resources

Cash Flows from Operating Activities. Net cash provided by operating activities was $706.5 million, $662.6 million and $645.6 million for the years ended December 31, 2017, 2016 and 2015 respectively. Operating cash flows and changes in working capital for comparative periods were as follows (in millions):

	Year Ended December 31,		
	2017	2016	2015
Operating cash flows before working capital	$ 755.8	$ 638.1	$ 613.7
Changes in working capital	(49.3)	24.5	31.9

Operating cash flows before changes in working capital increased $117.7 million for the year ended December 31, 2017 compared to the year ended December 31, 2016. This increase was primarily due to a $134.3 million increase in gross operating margin, excluding gains and losses on derivative activity, and a $26.0 million gain on litigation settlement, partially offset by a $23.8 million increase in interest expense, excluding amortization of debt issue costs and net discounts, and a $21.7 million decrease in cash received on derivative settlements.

Operating cash flows before changes in working capital increased $24.4 million for the year ended December 31, 2016 compared to the year ended December 31, 2015 primarily due to an increase in gross operating margin in our Oklahoma segment from the acquisition of the EnLink Oklahoma T.O. assets, which was partially offset by a decrease in gross operating margin in our Crude and Condensate segment due to lower volumes and the termination of a customer contract during the second quarter of 2015.

The changes in working capital for the years ended December 31, 2017, 2016 and 2015 were primarily due to fluctuations in trade receivable and payable balances due to timing of collection and payments and changes in inventory balances attributable to normal operating fluctuations.

Cash Flows from Investing Activities. Net cash used in investing activities was $610.8 million, $1,358.1 million and $1,097.3 million for the years ended December 31, 2017, 2016 and 2015, respectively. Our primary investing cash flows were as follows (in millions):

	Year Ended December 31,		
	2017	**2016**	**2015**
Growth capital expenditures	$ (758.4)	$ (632.5)	$ (530.0)
Maintenance capital expenditures	(32.4)	(30.5)	(42.3)
Acquisition of business, net of cash acquired	—	(769.3)	(524.2)
Proceeds from sale of unconsolidated affiliate investment	189.7	—	—
Proceeds from sale of property	2.3	93.1	1.0
Investment in unconsolidated affiliates	(12.6)	(73.8)	(25.8)
Distribution from unconsolidated affiliates in excess of earnings	0.2	54.6	21.1

Growth capital expenditures increased $125.9 million for the year ended December 31, 2017 compared to the year ended December 31, 2016. The increase was primarily due to capital expenditures related to the expansion of the Central Oklahoma assets and the Lobo processing facilities, as well as expenditures for the Greater Chickadee crude oil gathering system in the Permian Basin and the Ascension JV assets in Louisiana. Growth capital expenditures increased $102.5 million for the year ended December 31, 2016 compared to the year ended December 31, 2015. The increase was primarily due to gas processing and gathering expansion projects for our Central Oklahoma assets and the construction of the Lobo II processing facility, which is owned by the Delaware Basin JV.

Maintenance capital expenditures increased slightly by $1.9 million for the year ended December 31, 2017 compared to the year ended December 31, 2016. Maintenance capital expenditures decreased $11.8 million for the year ended December 31, 2016 compared to the year ended December 31, 2015. The decrease was primarily due to decreases in compressor overhauls in our Texas segment and decreases in other repairs in our Oklahoma and Louisiana segments.

Acquisition expenditures increased $245.1 million for the year ended December 31, 2016 compared to the year ended December 31, 2015. For the year ended December 31, 2016, we acquired the EnLink Oklahoma T.O. assets. For the year ended December 31, 2015, we acquired LPC, Coronado, Matador and Deadwood.

In December 2016, we entered into an agreement to sell our ownership interest in HEP. We finalized the sale in March 2017 and received net proceeds of $189.7 million. We received proceeds from sale of property of $93.1 million for the year ended December 31, 2016. These proceeds were primarily from the sale of the NTPL in December 2016 for $84.6 million.

Investments and distributions from unconsolidated affiliate investments are determined by our contribution and distribution activity with our GCF, HEP and Cedar Cove JV investments for the years ended December 31, 2017, 2016 and 2015. We formed the Cedar Cove JV with Kinder Morgan, Inc. during November 2016 and sold our ownership interest in our HEP investment during March 2017. See “Item 8. Financial Statements—Note 10” for investment and distribution activity.

Cash Flows from Financing Activities. Net cash used in financing activities was $76.5 million for the year ended December 31, 2017, and net cash provided by financing activities was $701.2 million and $448.0 million for the years ended December 31, 2016 and 2015, respectively. Our primary financing activities consisted of the following (in millions):

	Year Ended December 31,		
	2017	2016	2015
Net borrowings (repayments) on our credit facility	$ (120.0)	$ (294.2)	$ 176.8
Unsecured senior notes borrowings, net of notes extinguished	331.6	499.3	893.3
Proceeds from issuance of common units	106.9	167.5	24.4
Proceeds from issuance of Series B Preferred Units	—	724.1	—
Proceeds from issuance of Series C Preferred Units	394.0	—	—
Contributions by non-controlling partners	126.4	207.4	16.4
Payment of installment payable for EnLink Oklahoma T.O. acquisition	(250.0)	—	—
Proceeds from issuance of common units to general partner	—	—	50.0
Contribution from Devon	1.3	1.5	27.8

On May 11, 2017, we issued $500.0 million in aggregate principal amount of 5.450% senior unsecured notes due 2047 at a price to the public of 99.981% of their face value. Interest payments on the 2047 Notes are payable on June 1 and December 1 of each year, beginning December 1, 2017. Net proceeds of approximately $495.2 million were used to repay outstanding borrowings under the credit facility and for general partnership purposes. For the year ended December 31, 2017, we redeemed $162.5 million in aggregate principal amount of the 2022 Notes at 103.6% of the principal amount, plus accrued unpaid interest, for aggregate cash consideration of $174.1 million, which included payments for accrued interest of $5.8 million.

On July 14, 2016, we issued $500.0 million in aggregate principal amount of our 4.850% senior notes due 2026 (the “2026 Notes”) at a price to the public of 99.859% of their face value. The 2026 Notes mature on July 15, 2026. Interest payments on the 2026 Notes are payable on January 15 and July 15 of each year. Net proceeds of approximately $495.7 million were used to repay outstanding borrowings under our credit facility and for general partnership purposes.

On May 12, 2015, we issued $900.0 million aggregate principal amount of unsecured senior notes, consisting of $750.0 million aggregate principal amount of our 4.150% senior notes due 2025 (the “2025 Notes”) and an additional $150.0 million aggregate principal amount of 2045 Notes at prices to the public of 99.827% and 96.381%, respectively, of their face value. The 2025 Notes mature on June 1, 2025. Interest payments on the 2025 Notes are due semi-annually in arrears in June and December. The new 2045 Notes were offered as an additional issue of our outstanding 2045 Notes issued on November 12, 2014. The 2045 Notes issued on November 12, 2014 and May 12, 2015 are treated as a single class of debt securities and have identical terms, other than the issue date.

For the year ended December 31, 2017, we sold an aggregate of 6.2 million common units under the 2014 EDA and 2017 EDA, generating net proceeds of $106.9 million. For the year ended December 31, 2016, we sold an aggregate of 10.0 million common units under the 2014 EDA, generating net proceeds of $167.5 million. For the year ended December 31, 2015, we sold an aggregate of 1.3 million common units under the 2014 EDA, generating net proceeds of $24.4 million.

In January 2016, we issued an aggregate of 50,000,000 Series B Preferred Units for net proceeds of $724.1 million. See “Item 8. Financial Statements—Note 8” for additional information.

In September 2017, we issued 400,000 Series C Preferred Units for net proceeds of $394.0 million. See “Item 8. Financial Statements—Note 8” for additional information.

For the year ended December 31, 2017, contributions by non-controlling interests included $69.1 million from ENLC to EnLink Oklahoma T.O., $54.4 million from NGP to the Delaware Basin JV and $2.9 million from Marathon Petroleum to the Ascension JV. For the year ended December 31, 2016, contributions by non-controlling partners included $144.4 million in contributions from NGP to the Delaware Basin JV, which consisted of an initial contribution of $114.3 million that the Delaware Basin JV distributed to us at the formation of the joint venture to reimburse us for capital spent to the date of formation on existing assets, as well as $30.1 million for NGP’s share of ongoing projects. Contributions by non-controlling partners also included $39.5 million from ENLC for its share of costs incurred related to EnLink Oklahoma T.O and $23.5 million from Marathon Petroleum to the Ascension JV. For the year ended December 31, 2015, contributions by non-controlling partners included $12.5 million from Marathon Petroleum to the Ascension JV, and $3.9 million from other non-controlling interests.

For the year ended December 31, 2017, we paid $250.0 million for the second installment payable obligation related to the EnLink Oklahoma T.O. acquisition.

On October 29, 2015, we issued 2,849,100 common units at an offering price of $17.55 per unit to a subsidiary of ENLC for aggregate consideration of approximately $50.0 million in a private placement transaction.

Distributions to unitholders, our general partner and our non-controlling interests also represent a primary use of cash in financing activities. Total cash distributions made for the year ended December 31, 2017, 2016 and 2015 were as follows (in millions):

	Year Ended December 31,		
	2017	2016	2015
Common units	$ 543.6	$ 520.3	$ 436.1
General partner interest (including incentive distribution rights)	61.2	58.7	43.2
Distributions to non-controlling interests	27.5	10.0	66.5
Distributions to Series B Preferred Unitholders	15.9	—	—
Distributions to Series C Preferred Unitholders	5.6	—	—
Distributions to Devon for net assets acquired (1)	—	—	166.7

(1) Represents distributions to Devon related to VEX.

For the year ended December 31, 2017, distributions to non-controlling interest includes distributions to ENLC for its ownership in EnLink Oklahoma T.O., distributions to NGP for our Delaware Basin JV, distributions to Marathon Petroleum for our Ascension JV and distributions to the non-controlling interest in one of the E2 entities. For the year ended December 31, 2016, distributions to non-controlling interests includes distributions to redeem the non-controlling interest in one of the E2 entities and ENLC's ownership of EnLink Oklahoma T.O. For the year ended December 31, 2015, distributions to non-controlling interests includes distributions to ENLC relating to ENLC's prior ownership in EnLink Midstream Holdings, LP.

Series B Preferred Unit distributions for 2016 and for the first two quarters for 2017 were paid in-kind in the form of additional Series B Preferred Units. As these were non-cash distributions, they were not reflected in our financing cash flows for the years ended December 31, 2017 and 2016. Beginning with the quarter ended September 30, 2017, we paid Series B Preferred Unit distributions in cash at an amount per quarter equal to $0.28125 per Series B Preferred Unit (the "Cash Distribution Component") plus an in-kind distribution equal to the greater of (a) 0.0025 Series B Preferred Units per Series B Preferred Unit and (b) an amount equal to (i) the excess, if any, of the distributions that would have been payable had the Series B Preferred Units converted into common units for that quarter over the Cash Distribution Component, divided by (ii) the issue price of $15.00.

Distributions on the Series C Preferred Units accrue and are cumulative from the date of original issue and payable semi-annually in arrears on the 15th day of June and December of each year through and including December 15, 2022 and, thereafter, quarterly in arrears on the 15th day of March, June, September and December of each year, in each case, if and when declared by our general partner out of legally available funds for such purpose. The initial distribution rate for the Series C Preferred Units from and including the date of original issue to, but not including, December 15, 2022 is 6.0% per annum. On and after December 15, 2022, distributions on the Series C Preferred Units will accumulate for each distribution period at a percentage of the $1,000 liquidation preference per unit equal to an annual floating rate of the three-month LIBOR plus a spread of 4.11%.

Uncertainties. Our operations could be subject to changing environmental rules and regulations, the outcomes of which are currently unknown. See "Item 1. Business—Environmental Matters" for additional information.

Capital Requirements. We consider a number of factors in determining whether our capital expenditures are growth capital expenditures or maintenance capital expenditures. Growth capital expenditures generally include capital expenditures made for acquisitions or capital improvements that we expect will increase our asset base, operating income or operating capacity over the long-term. Examples of growth capital expenditures include the acquisition of assets and the construction or development of additional pipeline, storage, well connections, gathering or processing assets, in each case, to the extent such capital expenditures are expected to expand our asset base, operating capacity or our operating income.

Maintenance capital expenditures include capital expenditures made to replace partially or fully depreciated assets in order to maintain the existing operating capacity of the assets and to extend their useful lives. Examples of maintenance capital expenditures are expenditures to refurbish and replace pipelines, gathering assets, well connections, compression assets and processing assets up to their original operating capacity, or to maintain pipeline and equipment reliability, integrity and safety and to address environmental laws and regulations.

We expect our 2018 capital expenditures, including capital contributions to our unconsolidated affiliate investments, to be as follows (in millions):

		2018
Growth Capital Expenditures		
Texas segment	$	210 - 250
Louisiana segment		105 - 125
Oklahoma segment (1)		340 - 420
Crude and Condensate segment		40 - 50
Corporate segment		5 - 15
Total growth capital expenditures	$	700 - 860
Less: Growth capital expenditures funded by joint venture partners (2)		(115 - 145)
Growth capital expenditures, attributable to the Partnership	$	585 - 715
Maintenance Capital Expenditures	$	55 - 60

(1) Includes projected growth capital contributions related to our non-controlling interest share of the Cedar Cove JV.

(2) Includes growth capital expenditures that will be contributed by other entities and relate to the non-controlling interest share of our consolidated entities. These contributions include contributions by ENLC to EnLink Oklahoma T.O., contributions by NGP to the Delaware Basin JV and contributions by Marathon Petroleum to the Ascension JV.

Our primary capital projects for 2018 include the construction of the Thunderbird processing plant in Central Oklahoma, the Lobo III processing plant in the Delaware Basin and the development of additional gathering and compression assets in Central Oklahoma and the Permian Basin. See “Recent Developments” for further details.

We expect to fund growth capital expenditures from the proceeds of borrowings underour credit facility and proceeds from other debt and equity sources, including capital contributions by joint venture partners that relate to the non-controlling interest share of our consolidated entities. We expect to fund our maintenance capital expenditures from operating cash flows. In 2018, it is possible that not all of the planned projects will be commenced or completed. Our ability to pay distributions to our unitholders, to fund planned capital expenditures and to make acquisitions will depend upon our future operating performance, which will be affected by prevailing economic conditions in the industry, financial, business and other factors, some of which are beyond our control.

Off-Balance Sheet Arrangements. We had no off-balance sheet arrangements as of December 31, 2017, 2016 and 2015.

Total Contractual Cash Obligations. A summary of our total contractual cash obligations as ofDecember 31, 2017 is as follows (in millions):

	Payments Due by Period						
	Total	2018	2019	2020	2021	2022	Thereafter
Long-term debt obligations	$ 3,500.0	$ —	$ 400.0	$ —	$ —	$ —	$ 3,100.0
Interest payable on fixed long-term debt obligations	2,573.4	159.9	154.5	149.2	149.2	149.2	1,811.4
Installment payable obligations (1)	250.0	250.0	—	—	—	—	—
Capital lease obligations	4.4	1.5	1.5	1.4	—	—	—
Operating lease obligations	109.6	14.3	10.9	8.6	8.6	8.6	58.6
Purchase obligations	2.7	2.7	—	—	—	—	—
Delivery contract obligation	26.9	17.9	9.0	—	—	—	—
Pipeline capacity and deficiency agreements (2)	91.7	19.3	14.3	8.9	8.8	8.8	31.6
Inactive easement commitment (3)	10.0	—	—	—	—	10.0	—
Total contractual obligations	$ 6,568.7	$ 465.6	$ 590.2	$ 168.1	$ 166.6	$ 176.6	$ 5,001.6

(1) Amounts relate to the final installment payable that was paid in January 2018 for the acquisition of the EnLink Oklahoma T.O. assets.
(2) Consists of pipeline capacity payments for firm transportation and deficiency agreements.
(3) Amounts related to inactive easements paid as utilized by us with balance due in 2022 if not utilized.

The above table does not include any physical or financial contract purchase commitments for natural gas due to the nature of both the price and volume components of such purchases, which vary on a daily or monthly basis. Additionally, we do not have contractual commitments for fixed price and/or fixed quantities of any material amount.

The interest payable under our credit facility is not reflected in the above table because such amounts depend on the outstanding balances and interest rates, which vary from time to time.

In January 2018, we paid the final $250.0 million installment payable obligation related to the EnLink Oklahoma T.O. acquisition. We funded this installment payment using various sources, including proceeds from the Series C Preferred Units issued in September 2017, proceeds from common unit issuances under the 2017 EDA and borrowings under our credit facility. Our contractual cash obligations for the remainder of 2018 are expected to be funded from cash flows generated from our operations, proceeds from our common unit issuances under the 2017 EDA, asset sales and borrowings underour credit facility.

Indebtedness

We have a $1.5 billion unsecured revolving credit facility that matures on March 6, 2020, and includes a$500.0 million letter of credit subfacility. As of December 31, 2017, there were $9.8 million in outstanding letters of credit and no outstanding borrowings under our credit facility, leaving approximately $1.5 billion available for future borrowing.

In addition, we have $3.5 billion aggregate principal amount of outstanding unsecured senior notes as of December 31, 2017 with $400.0 million maturing in April 2019 and the remaining maturities beginning in 2024 and ending in 2047.

See “Item 8. Financial Statements—Note 6” for more information on our outstanding debt instruments.

Credit Risk

Risks of nonpayment and nonperformance by our customers are a major concern in our business. We are subject to risks of loss resulting from nonpayment or nonperformance by our customers and other counterparties, such as our lenders and hedging counterparties. Any increase in the nonpayment and nonperformance by our customers could adversely affect our results of operations and reduce our ability to make distributions to our unitholders.

Inflation

Inflation in the United States has been relatively low in recent years in the economy as a whole. The midstream natural gas industry’s labor and material costs remained relatively unchanged in 2015, 2016 and 2017. Although the impact of inflation has been insignificant in recent years, it is still a factor in the United States economy and may increase the cost to acquire or replace property and equipment and may increase the costs of labor and supplies. To the extent permitted by competition, regulation and our existing agreements, we have and will continue to pass along increased costs to our customers in the form of higher fees.

Environmental

Our operations are subject to environmental laws and regulations adopted by various governmental authorities in the jurisdictions in which these operations are conducted. We believe we are in material compliance with all applicable laws and regulations. For a more complete discussion of the environmental laws and regulations that impact us, see "Item 1. Business—Environmental Matters."

Contingencies

See "Item 8. Financial Statements and Supplementary Data—Note 14."

Recent Accounting Pronouncements

See "Item 8. Financial Statements and Supplementary Data—Note 2" for more information on recently issued and adopted accounting pronouncements.

Disclosure Regarding Forward-Looking Statements

This Annual Report on Form 10-K contains forward-looking statements that are based on information currently available to management as well as management's assumptions and beliefs. All statements, other than statements of historical fact, included in this Annual Report constitute forward-looking statements, including but not limited to statements identified by the words "forecast," "may," "believe," "will," "should," "plan," "predict," "anticipate," "intend," "estimate" and "expect" and similar expressions. Such statements reflect our current views with respect to future events, based on what we believe are reasonable assumptions; however, such statements are subject to certain risks and uncertainties. In addition to the specific uncertainties discussed elsewhere in this Annual Report, the risk factors set forth in "Item 1A. Risk Factors" may affect our performance and results of operations. Should one or more of these risks or uncertainties materialize, or should underlying assumptions prove incorrect, actual results may differ materially from those in the forward-looking statements. We disclaim any intention or obligation to update or review any forward-looking statements or information, whether as a result of new information, future events or otherwise.

Item 7A. Quantitative and Qualitative Disclosures about Market Risk

Market risk is the risk of loss arising from adverse changes in market rates and prices. Our primary market risk is the risk related to changes in the prices of natural gas, NGLs, condensate and crude oil. In addition, we are also exposed to the risk of changes in interest rates on floating rate debt.

Comprehensive financial reform legislation was signed into law by the President on July 21, 2010. The legislation calls for the U.S. Commodity Futures Trading Commission ("CFTC") to regulate certain markets for derivative products, including over-the-counter ("OTC") derivatives. The CFTC has issued several new relevant regulations that mandate that certain derivatives products be subject to margin requirements, cleared at a clearinghouse or executed on an exchange. While some of these rules have been finalized, some have not and, as a result, the final form and timing of the implementation of the new regulatory regime affecting commodity derivatives remains uncertain.

In particular, on October 18, 2011, the CFTC adopted final rules under the Dodd-Frank Act establishing position limits for certain energy commodity futures and options contracts and economically equivalent swaps, futures and options. The CFTC's original position limits rule was challenged in court by two industry associations and was vacated and remanded by a federal district court. The CFTC has withdrawn its appeal of the court order vacating the original position limits rule. However, in November 2013, the CFTC proposed new rules that would place limits on positions in certain core futures and equivalent swaps contracts for or linked to certain physical commodities, subject to exceptions for certain bona fide hedging transactions. In December 2016, the CFTC modified and reproposed its positions limits rules. The CFTC has sought comment on the position limits rule as reproposed, but these new position limit rules are not yet final and the impact of those provisions on us is uncertain at this time.

The legislation and new regulations may also require counterparties to our derivative instruments to spin off some of their derivatives activities to separate entities, which may not be as creditworthy as the current counterparties. The new legislation and any future new regulations could significantly increase the cost of derivative contracts, materially alter the terms of derivative contracts, reduce the availability of derivatives to protect against risks we encounter, reduce our ability to monetize or restructure our existing derivative contracts and increase our exposure to less creditworthy counterparties. If we reduce our use of derivatives 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 to generate sufficient cash flow to pay quarterly distributions at current levels or at all. Our revenues could be adversely affected if a consequence of the legislation and regulations is lower commodity prices. Any of these consequences could have a material, adverse effect on us, our financial condition and our results of operations.

Commodity Price Risk

The prices of crude oil, condensate, natural gas and NGLs were volatile during 2017. Crude oil and weighted average NGL prices increased 15% and 21%, respectively, while natural gas prices decreased 11% from January 1, 2017 to December 31, 2017. We expect continued volatility in these commodity prices. For example, crude oil prices (based on the NYMEX futures daily close prices for the prompt month) in 2017 ranged from a high of $60.42 per Bbl in December 2017 to a low of $42.53 per Bbl in June 2017. Weighted average NGL prices in 2017 (based on the Oil Price Information Service (“OPIS”) Napoleonville daily average spot liquids prices) ranged from a high of $0.78 per gallon in February 2017 to a low of $0.41 per gallon in January 2017. Natural gas prices (based on Gas Daily Henry Hub closing prices) during 2017 ranged from a high of $3.42 per MMBtu in May 2017 to a low of $2.56 per MMBtu in February 2017.

Changes in commodity prices may indirectly impact our profitability by influencing drilling activity and well operations, and thus the volume of gas, NGLs, crude oil and condensate connected to or near our assets and on our fees earned for transportation between certain market centers. Low prices for these products could reduce the demand for our services and volumes in our systems. The volatility in commodity prices may cause our gross operating margin and cash flows to vary widely from period to period. Our hedging strategies may not be sufficient to offset price volatility risk and, in any event, do not cover all of our throughput volumes.

We are subject to risks due to fluctuations in commodity prices. Approximately 94% of our gross operating margin for the year ended December 31, 2017 was generated from arrangements with fee-based structures with minimal direct commodity price exposure. Our exposure to these commodity price fluctuations is primarily in the gas processing component of our business. We currently process gas under four main types of contractual arrangements (or a combination of these types of contractual arrangements) as summarized below.

1. *Fee-based contracts:* Under fee-based contracts, we earn our fees through (1) stated fixed-fee arrangements in which we are paid a fixed fee per unit of volume processed or (2) arrangements where we purchase and resell commodities in connection with providing the related processing service and earn a net margin through a fee-like deduction subtracted from the purchase price of the commodities.

2. *Processing margin contracts:* Under these contracts, we pay the producer for the full amount of inlet gas to the plant, and we make a margin based on the difference between the value of liquids recovered from the processed natural gas as compared to the value of the natural gas volumes lost and the cost of fuel used in processing. The shrink and fuel losses are referred to as plant thermal reduction, or PTR. Our margins from these contracts are high during periods of high liquids prices relative to natural gas prices and can be negative during periods of high natural gas prices relative to liquids prices. However, we mitigate our risk of processing natural gas when margins are negative primarily through our ability to bypass processing when it is not profitable for us or by contracts that revert to a minimum fee for processing if the natural gas must be processed to meet pipeline quality specifications. For the year ended December 31, 2017, approximately 1.3% of our contracts, based on gross operating margin, were under processing margin contracts.

3. *Percent of liquids contracts:* Under these contracts, we receive a fee in the form of a percentage of the liquids recovered, and the producer bears all the cost of the natural gas shrink. Therefore, our margins from these contracts are greater during periods of high liquids prices. Our margins from processing cannot become negative under percent of liquids contracts, but they do decline during periods of low liquids prices.

4. *Percent of proceeds contracts:* Under these contracts, we receive a fee as a portion of the proceeds of the sale of natural gas and liquids. Therefore, our margins from these contracts are greater during periods of high natural gas and

liquids prices. Our margins from processing cannot become negative under percent of proceeds contracts, but they do decline during periods of low natural gas and liquids prices.

For the year ended December 31, 2017, approximately 3.4% of our contracts, based on gross operating margin, were processed under percent of liquids or percent of proceeds contracts.

Our primary commodity risk management objective is to reduce volatility in our cash flows. We maintain a risk management committee, including members of senior management, which oversees all hedging activity. We enter into hedges for natural gas and NGLs using over-the-counter derivative financial instruments with only certain well-capitalized counterparties which have been approved by our risk management committee.

We have hedged our exposure to fluctuations in prices for natural gas and NGL volumes produced for our account. We hedge our exposure based on volumes we consider hedgeable (volumes committed under contracts that are long term in nature) versus total volumes that include volumes that may fluctuate due to contractual terms, such as contracts with month-to-month processing options. Further, we have tailored our hedges to generally match the NGL product composition and the NGL and natural gas delivery points to those of our physical equity volumes. The NGL hedges cover specific NGL products based upon our expected equity NGL composition.

The following table sets forth certain information related to derivative instruments outstanding at December 31, 2017 mitigating the risks associated with the gas processing and fractionation components of our business. The relevant payment index price for liquids is the monthly average of the daily closing price for deliveries of commodities into Mont Belvieu, Texas as reported by OPIS. The relevant index price for natural gas is Henry Hub Gas Daily as defined by the pricing dates in the swap contracts.

Period	Underlying	Notional Volume	We Pay	We Receive (1)	Fair Value Asset/(Liability) (In millions)
January 2018 - December 2018	Ethane	384 (MBbls)	$0.2639/gal	Index	$ (0.2)
January 2018 - December 2018	Propane	681 (MBbls)	Index	$0.8758/gal	(3.7)
January 2018 - December 2018	Normal Butane	362 (MBbls)	Index	$0.9235/gal	0.7
January 2018 - December 2018	Natural Gasoline	89 (MBbls)	Index	$1.3759/gal	(0.6)
January 2018 - January 2019	Natural Gas	122,629 (MMBtu/d)	Index	$2.5664/MMBtu	2.2
					$ (1.6)

(1) Weighted average.

Another price risk we face is the risk of mismatching volumes of gas bought or sold on a monthly price versus volumes bought or sold on a daily price. We enter each month with a balanced book of natural gas bought and sold on the same basis. However, it is normal to experience fluctuations in the volumes of natural gas bought or sold under either basis, which leaves us with short or long positions that must be covered. We use financial swaps to mitigate the exposure at the time it is created to maintain a balanced position.

The use of financial instruments may expose us to the risk of financial loss in certain circumstances, including instances when (1) sales volumes are less than expected requiring market purchases to meet commitments or (2) counterparties fail to purchase the contracted quantities of natural gas or otherwise fail to perform. To the extent that we engage in hedging activities, we may be prevented from realizing the benefits of favorable price changes in the physical market. However, we are similarly insulated against unfavorable changes in such prices.

As of December 31, 2017, outstanding natural gas swap agreements, NGL swap agreements, swing swap agreements, storage swap agreements and other derivative instruments were a net fair value liability of $1.6 million. The aggregate effect of a hypothetical 10% change, increase or decrease, in gas and NGL prices would result inan immaterial change in the approximate net fair value of these contracts as of December 31, 2017.

Interest Rate Risk

We are exposed to interest rate risk on our variable rate credit facility. At December 31, 2017, we had no outstanding borrowings under this facility.

We are not exposed to changes in interest rates with respect to our senior unsecured notes due in 2019, 2024, 2025, 2026, 2044, 2045 or 2047 as these are fixed-rate obligations. The estimated fair value of our senior unsecured notes was approximately $3,575.6 million as of December 31, 2017, based on market prices of similar debt at December 31, 2017. Market risk is estimated as the potential decrease in fair value of our long-term debt resulting from a hypothetical increase of 1% in interest rates. Such an increase in interest rates would result in an approximate $290.3 million decrease in fair value of our senior unsecured notes at December 31, 2017.

Item 8. Financial Statements and Supplementary Data

INDEX TO FINANCIAL STATEMENTS

EnLink Midstream Partners, LP Financial Statements:

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Management of EnLink Energy GP, LLC is responsible for establishing and maintaining adequate internal control over financial reporting and for the assessment of the effectiveness of internal control over financial reporting for EnLink Midstream Partners, LP (the "Partnership"). As defined by the Securities and Exchange Commission (Rule 13a-15(f) under the Securities Exchange Act of 1934, as amended), internal control over financial reporting is a process designed by, or under the supervision of EnLink Energy GP, LLC's principal executive and principal financial officers and effected by its 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 U.S. generally accepted accounting principles.

The Partnership's internal control over financial reporting is supported by written 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 U.S. generally accepted accounting principles, and that receipts and expenditures of the Partnership are being made only in accordance with authorization of the EnLink Energy GP, LLC's management and directors; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of the Partnership's assets that could have a material effect on the consolidated financial statements.

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

In connection with the preparation of the Partnership's annual consolidated financial statements, management has undertaken an assessment of the effectiveness of the Partnership's internal control over financial reporting as of December 31, 2017, based on criteria established in *Internal Control—Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (the COSO Framework). Management's assessment included an evaluation of the design of the Partnership's internal control over financial reporting and testing of the operational effectiveness of those controls.

Based on this assessment, management has concluded that as ofDecember 31, 2017, the Partnership's internal control over financial reporting was effective to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with U.S. generally accepted accounting principles.

KPMG LLP, the independent registered public accounting firm that audited the Partnership's consolidated financial statements included in this report, has issued an attestation report on the Partnership's internal control over financial reporting, a copy of which appears on the following page of this Annual Report on Form 10-K.

Report of Independent Registered Public Accounting Firm

The Partners and Board of Directors
EnLink Midstream Partners, LP:

Opinions on the Consolidated Financial Statements and Internal Control Over Financial Reporting

We have audited the accompanying consolidated balance sheets of EnLink Midstream Partners, LP (a Delaware limited partnership) and subsidiaries as of December 31, 2017 and 2016, the related consolidated statements of operations, comprehensive income (loss), changes in partners' equity, and cash flows for each of the years in the three-year period ended December 31, 2017, and the related notes (collectively, the "consolidated financial statements"). We also have audited EnLink Midstream Partners, LP's internal control over financial reporting as of December 31, 2017, based on criteria established in *Internal Control—Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of EnLink Midstream Partners, LP as of December 31, 2017 and 2016, and the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2017, in conformity with U.S. generally accepted accounting principles. Also in our opinion, EnLink Midstream Partners, LP maintained, in all material respects, effective internal control over financial reporting as of December 31, 2017, based on criteria established in *Internal Control—Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

Basis for Opinion

EnLink Midstream Partners, LP's management is responsible for these consolidated financial statements, 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 EnLink Midstream Partners, LP's consolidated financial statements and an opinion on EnLink Midstream Partners, LP's internal control over financial reporting based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) ("PCAOB") and are required to be independent with respect to EnLink Midstream Partners, LP in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud, and whether effective internal control over financial reporting was maintained in all material respects.

Our audits of the consolidated financial statements included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

Definition and Limitations of Internal Control Over Financial Reporting

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

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

/s/ KPMG LLP

We have served as EnLink Midstream Partners, LP's auditor since 2013.

Dallas, Texas
February 21, 2018

ENLINK MIDSTREAM PARTNERS, LP
Consolidated Balance Sheets
(In millions, except unit data)

	December 31, 2017	December 31, 2016
ASSETS		
Current assets:		
Cash and cash equivalents	$ 30.8	$ 11.6
Accounts receivable:		
Trade, net of allowance for bad debt of $0.3 and $0.1, respectively	50.1	63.9
Accrued revenue and other	576.6	369.6
Related party	102.7	100.2
Fair value of derivative assets	6.8	1.3
Natural gas and NGLs inventory, prepaid expenses and other	39.7	31.0
Investment in unconsolidated affiliates—current	—	193.1
Total current assets	806.7	770.7
Property and equipment, net of accumulated depreciation of $2,533.0 and $2,124.1, respectively	6,587.0	6,256.7
Intangible assets, net of accumulated amortization of $298.7 and $171.6, respectively	1,497.1	1,624.2
Goodwill	422.3	422.3
Investment in unconsolidated affiliates—non-current	89.4	77.3
Other assets, net	11.5	2.2
Total assets	$ 9,414.0	$ 9,153.4
LIABILITIES AND PARTNERS' EQUITY		
Current liabilities:		
Accounts payable and drafts payable	$ 66.9	$ 69.2
Accounts payable to related party	18.4	10.4
Accrued gas, NGLs, condensate and crude oil purchases	476.1	333.3
Fair value of derivative liabilities	8.4	7.6
Installment payable, net of discount of $0.5 and $0.5, respectively	249.5	249.5
Other current liabilities	222.4	217.0
Total current liabilities	1,041.7	887.0
Long-term debt	3,467.8	3,268.0
Asset retirement obligations	14.2	13.5
Installment payable, net of discount of $26.3 at December 31, 2016	—	223.7
Other long-term liabilities	33.9	42.6
Deferred tax liability	46.3	73.0
Redeemable non-controlling interest	4.6	5.2
Partners' equity:		
Common unitholders (349,702,372 and 342,856,292 units issued and outstanding, respectively)	2,791.6	3,193.2
Series B preferred unitholders (57,056,281 and 53,182,651 units issued and outstanding, respectively)	864.1	794.0
Series C preferred unitholders (400,000 units issued and outstanding at December 31, 2017)	395.1	—
General partner interest (1,594,974 equivalent units outstanding)	207.3	209.1
Accumulated other comprehensive loss	(2.1)	—
Non-controlling interest	549.5	444.1
Total partners' equity	4,805.5	4,640.4
Commitments and contingencies (Note 14)		
Total liabilities and partners' equity	$ 9,414.0	$ 9,153.4

See accompanying notes to consolidated financial statements.

ENLINK MIDSTREAM PARTNERS, LP
Consolidated Statements of Operations
(In millions, except per unit data)

	Year Ended December 31,		
	2017	2016	2015
Revenues:			
Product sales	$ 4,358.4	$ 3,008.9	$ 3,253.7
Product sales—related parties	144.9	134.3	119.4
Midstream services	552.3	467.2	451.0
Midstream services—related parties	688.2	653.1	618.6
Gain (loss) on derivative activity	(4.2)	(11.1)	9.4
Total revenues	5,739.6	4,252.4	4,452.1
Operating costs and expenses:			
Cost of sales (1)	4,361.5	3,015.5	3,245.3
Operating expenses	418.7	398.5	419.9
General and administrative	123.5	119.3	132.4
Loss on disposition of assets	—	13.2	1.2
Depreciation and amortization	545.3	503.9	387.3
Impairments	17.1	566.3	1,563.4
Gain on litigation settlement	(26.0)	—	—
Total operating costs and expenses	5,440.1	4,616.7	5,749.5
Operating income (loss)	299.5	(364.3)	(1,297.4)
Other income (expense):			
Interest expense, net of interest income	(187.9)	(188.1)	(102.5)
Gain on extinguishment of debt	9.0	—	—
Income (loss) from unconsolidated affiliates	9.6	(19.9)	20.4
Other income	0.6	0.3	0.8
Total other expense	(168.7)	(207.7)	(81.3)
Income (loss) before non-controlling interest and income taxes	130.8	(572.0)	(1,378.7)
Income tax benefit (provision)	24.0	(1.3)	0.5
Net income (loss)	154.8	(573.3)	(1,378.2)
Net income (loss) attributable to non-controlling interest	5.9	(8.1)	(0.4)
Net income (loss) attributable to EnLink Midstream Partners, LP	$ 148.9	$ (565.2)	$ (1,377.8)
General partner interest in net income	$ 38.3	$ 39.5	$ 58.0
Limited partners' interest in net income (loss) attributable to EnLink Midstream Partners, LP	$ 17.9	$ (662.1)	$ (1,405.2)
Class C partners' interest in net loss attributable to EnLink Midstream Partners, LP	$ —	$ (12.5)	$ (30.6)
Series B preferred interest in net income attributable to EnLink Midstream Partners, LP	$ 86.0	$ 69.9	$ —
Series C preferred interest in net income attributable to EnLink Midstream Partners, LP	$ 6.7	$ —	$ —
Net income (loss) attributable to EnLink Midstream Partners, LP per limited partners' unit:			
Basic common unit	$ 0.05	$ (1.99)	$ (4.66)
Diluted common unit	$ 0.05	$ (1.99)	$ (4.66)

(1) Includes related party cost of sales of $211.0 million, $150.1 million and $141.3 million for the years ended December 31, 2017, 2016 and 2015, respectively.

See accompanying notes to consolidated financial statements.

ENLINK MIDSTREAM PARTNERS, LP
Consolidated Statements of Comprehensive Income (Loss)
(In millions)

	Year Ended December 31,		
	2017	2016	2015
Net income (loss)	$ 154.8	$ (573.3)	$ (1,378.2)
Loss on designated cash flow hedge, net of amortization to interest expense	(2.1)	—	—
Comprehensive income (loss)	152.7	(573.3)	(1,378.2)
Comprehensive income (loss) attributable to non-controlling interest	5.9	(8.1)	(0.4)
Comprehensive income (loss) attributable to EnLink Midstream Partners, LP	$ 146.8	$ (565.2)	$ (1,377.8)

See accompanying notes to consolidated financial statements.

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ENLINK MIDSTREAM PARTNERS, LP
Consolidated Statements of Changes in Partners' Equity
(In millions)

	Common Units		Class C Common Units		Series B Preferred Units		Series C Preferred Units		General Partner Interest		Accumulated Other Comprehensive Loss	Non-Controlling Interest	Total	Redeemable Non-Controlling Interest (Temporary Equity)
	$	Units	$	Units	$	Units	$	Units	$	Units	$	$	$	$
Balance, December 31, 2014	$ 5,833.3	245.4	$ —	—	$ —	—	$ —	—	$ 180.3	1.6	$ —	$ 12.3	$ 6,025.9	$ —
Issuance of common units	204.3	76.8	180.0	6.7	—	—	—	—	—	—	—	—	384.3	—
Issuance of common units to ENLC	50.0	2.8	—	—	—	—	—	—	—	—	—	—	50.0	—
Conversion of restricted units for common units, net of units withheld for taxes	(2.5)	0.2	—	—	—	—	—	—	—	—	—	—	(2.5)	—
Unit-based compensation	17.4	—	—	—	—	—	—	—	18.3	—	—	—	35.7	—
Contribution from Devon	27.8	—	—	—	—	—	—	—	—	—	—	—	27.8	—
Distribution attributable to VEX interests transferred (Note 3)	(166.7)	—	—	—	—	—	—	—	—	—	—	—	(166.7)	—
Distributions	(436.1)	—	—	0.4	—	—	—	—	(43.2)	—	—	—	(479.3)	—
Non-controlling interest contributions	—	—	—	—	—	—	—	—	—	—	—	16.4	16.4	—
Distributions to non-controlling interest	—	—	—	—	—	—	—	—	—	—	—	(66.5)	(66.5)	—
Adjustment related to mandatory redemption of E2 non-controlling interest	—	—	—	—	—	—	—	—	—	—	—	(5.4)	(5.4)	—
Redeemable non-controlling interest	—	—	—	—	—	—	—	—	—	—	—	(7.0)	(7.0)	7.0
Transfer of interest in Midstream Holdings	(66.5)	—	—	—	—	—	—	—	—	—	—	66.5	—	—
Net income (loss)	(1,405.2)	—	(30.6)	—	—	—	—	—	58.0	—	—	(0.4)	(1,378.2)	—
Balance, December 31, 2015	$ 4,055.8	325.2	$ 149.4	7.1	$ —	—	$ —	—	$ 213.4	1.6	$ —	$ 15.9	$ 4,434.5	$ 7.0
Issuance of common units	167.5	10.0	—	—	—	—	—	—	—	—	—	—	167.5	—
Issuance of Series B Preferred Units	—	—	—	—	724.1	50.0	—	—	—	—	—	—	724.1	—
Contribution from ENLC	—	—	—	—	—	—	—	—	—	—	—	237.1	237.1	—
Conversion of restricted units for common units, net of units withheld for taxes	(1.2)	0.2	—	—	—	—	—	—	—	—	—	—	(1.2)	—
Unit-based compensation	15.1	—	—	—	—	—	—	—	14.9	—	—	—	30.0	—
Contribution from Devon	1.5	—	—	—	—	—	—	—	—	—	—	—	1.5	—
Distributions	(520.3)	—	—	0.4	—	3.2	—	—	(58.7)	—	—	—	(579.0)	—
Conversion of Class C Common Units to common units	136.9	7.5	(136.9)	(7.5)	—	—	—	—	—	—	—	—	—	—
Non-controlling interest contributions	—	—	—	—	—	—	—	—	—	—	—	207.4	207.4	—
Distributions to non-controlling interest	—	—	—	—	—	—	—	—	—	—	—	(8.2)	(8.2)	—
Distributions to redeemable non-controlling interest	—	—	—	—	—	—	—	—	—	—	—	—	—	(1.8)
Net income (loss)	(662.1)	—	(12.5)	—	69.9	—	—	—	39.5	—	—	(8.1)	(573.3)	—
Balance, December 31, 2016	$ 3,193.2	342.9	$ —	—	$ 794.0	53.2	$ —	—	$ 209.1	1.6	$ —	$ 444.1	$ 4,640.4	$ 5.2

See accompanying notes to consolidated financial statements.

ENLINK MIDSTREAM PARTNERS, LP
Consolidated Statements of Changes in Partners' Equity (continued)
(In millions)

	Common Units		Class C Common Units		Series B Preferred Units		Series C Preferred Units		General Partner Interest		Accumulated Other Comprehensive Loss	Non-Controlling Interest	Total	Redeemable Non-Controlling Interest (Temporary Equity)
	$	Units	$	Units	$	Units	$	Units	$	Units	$	$	$	$
Balance, December 31, 2016	$ 3,193.2	342.9	$ —	—	$ 794.0	53.2	$ —	—	$ 209.1	1.6	$ —	$ 444.1	$ 4,640.4	$ 5.2
Issuance of common units	106.9	6.2	—	—	—	—	—	—	—	—	—	—	106.9	—
Issuance of Series C Preferred Units	—	—	—	—	—	—	394.0	0.4	—	—	—	—	394.0	—
Conversion of restricted units for common units, net of units withheld for taxes	(5.3)	0.6	—	—	—	—	—	—	—	—	—	—	(5.3)	—
Unit-based compensation	21.2	—	—	—	—	—	—	—	21.1	—	—	—	42.3	—
Contribution from Devon	1.3	—	—	—	—	—	—	—	—	—	—	—	1.3	—
Distributions	(543.6)	—	—	—	(15.9)	3.9	(5.6)	—	(61.2)	—	—	—	(626.3)	—
Non-controlling interest contributions	—	—	—	—	—	—	—	—	—	—	—	126.4	126.4	—
Distributions to non-controlling interest	—	—	—	—	—	—	—	—	—	—	—	(26.9)	(26.9)	—
Distributions to redeemable non-controlling interest	—	—	—	—	—	—	—	—	—	—	—	—	—	(0.6)
Unrealized loss on derivatives, net of amortization to interest expense	—	—	—	—	—	—	—	—	—	—	(2.1)	—	(2.1)	—
Net income	17.9	—	—	—	86.0	—	6.7	—	38.3	—	—	5.9	154.8	—
Balance, December 31, 2017	$ 2,791.6	349.7	$ —	—	$ 864.1	57.1	$ 395.1	0.4	$ 207.3	1.6	$ (2.1)	$ 549.5	$ 4,805.5	$ 4.6

See accompanying notes to consolidated financial statements.

ENLINK MIDSTREAM PARTNERS, LP
Consolidated Statements of Cash Flows
(In millions)

	Year Ended December 31, 2017	2016	2015
Cash flows from operating activities:			
Net income (loss)	$ 154.8	$ (573.3)	$ (1,378.2)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Impairments	17.1	566.3	1,563.4
Depreciation and amortization	545.3	503.9	387.3
Loss on disposition of assets	—	13.2	1.2
Non-cash unit-based compensation	47.8	30.0	35.7
Deferred tax benefit	(26.6)	(0.6)	(3.6)
(Gain) loss on derivatives recognized in net income (loss)	4.2	11.1	(9.4)
Cash settlements on derivatives	(11.2)	10.5	17.1
Gain on extinguishment of debt	(9.0)	—	—
Amortization of debt issue costs, net (premium) discount of notes and installment payable	29.1	53.1	0.2
Distribution of earnings from unconsolidated affiliates	13.3	3.1	21.6
(Income) loss from unconsolidated affiliates	(9.6)	19.9	(20.4)
Other operating activities	0.6	0.9	(1.2)
Changes in assets and liabilities, net of assets acquired and liabilities assumed:			
Accounts receivable, accrued revenue and other	(189.5)	(117.9)	197.4
Natural gas and NGLs inventory, prepaid expenses and other	(23.7)	10.2	4.2
Accounts payable, accrued gas and crude oil purchases and other accrued liabilities	163.9	132.2	(169.7)
Net cash provided by operating activities	706.5	662.6	645.6
Cash flows from investing activities, net of assets acquired and liabilities assumed:			
Additions to property and equipment	(790.8)	(663.0)	(572.3)
Proceeds from insurance settlement	0.4	0.3	2.9
Acquisition of business, net of cash acquired	—	(769.3)	(524.2)
Proceeds from sale of unconsolidated affiliate investment	189.7	—	—
Proceeds from sale of property	2.3	93.1	1.0
Investment in unconsolidated affiliates	(12.6)	(73.8)	(25.8)
Distribution from unconsolidated affiliates in excess of earnings	0.2	54.6	21.1
Net cash used in investing activities	(610.8)	(1,358.1)	(1,097.3)
Cash flows from financing activities:			
Proceeds from borrowings	2,315.9	2,057.8	3,204.4
Payments on borrowings	(2,104.3)	(1,852.7)	(2,134.3)
Payment of installment payable for EnLink Oklahoma T.O. acquisition	(250.0)	—	—
Debt financing costs	(5.5)	(4.6)	(9.5)
Proceeds from issuance of common units	106.9	167.5	24.4
Proceeds from issuance of common units to general partner	—	—	50.0
Proceeds from issuance of Series B Preferred Units	—	724.1	—
Proceeds from issuance of Series C Preferred Units	394.0	—	—
Distribution to common unitholders and to general partner	(604.8)	(579.0)	(479.3)
Distributions to Series B Preferred Unitholders	(15.9)	—	—
Distributions to Series C Preferred Unitholders	(5.6)	—	—
Distributions to non-controlling interests	(27.5)	(10.0)	(66.5)
Contributions by non-controlling interests, including contributions from affiliates of $69.1, $39.5 and $0.0, respectively	126.4	207.4	16.4
Distributions to Devon for net assets acquired	—	—	(166.7)
Contribution from Devon	1.3	1.5	27.8
Other financing activities	(7.4)	(10.8)	(18.7)
Net cash provided by (used in) financing activities	(76.5)	701.2	448.0
Net increase (decrease) in cash and cash equivalents	19.2	5.7	(3.7)
Cash and cash equivalents, beginning of period	11.6	5.9	9.6
Cash and cash equivalents, end of period	$ 30.8	$ 11.6	$ 5.9
Cash paid for interest	$ 163.8	$ 132.5	$ 109.4
Cash paid for income taxes	$ 4.8	$ 2.8	$ 0.5

See accompanying notes to consolidated financial statements.

(1) Organization and Summary of Significant Agreements

(a) Organization of Business and Nature of Business

EnLink Midstream Partners, LP is a publicly traded Delaware limited partnership formed in 2002. Our common units are traded on the New York Stock Exchange under the symbol "ENLK." Our business activities are conducted through our subsidiary, EnLink Midstream Operating, LP, a Delaware limited partnership (the "Operating Partnership"), and the subsidiaries of the Operating Partnership.

EnLink Midstream GP, LLC, a Delaware limited liability company, is our general partner. Our general partner manages our operations and activities. Our general partner is an indirect wholly-owned subsidiary of EnLink Midstream, LLC ("ENLC"). ENLC's units are traded on the New York Stock Exchange under the symbol "ENLC." Devon Energy Corporation ("Devon") owns ENLC's managing member and common units representing approximately 64% of the outstanding limited liability company interests in ENLC.

Effective as of March 7, 2014, the Operating Partnership acquired (the "Acquisition") 50% of the outstanding equity interests in EnLink Midstream Holdings, LP ("Midstream Holdings") and all of the outstanding equity interests in EnLink Midstream Holdings GP, LLC, the general partner of Midstream Holdings, in exchange for the issuance by us of 120,542,441 units of our limited partnership interests. At the same time, EnLink Midstream, Inc. ("EMI"), the entity that directly owns our general partner, became a wholly-owned subsidiary of ENLC (together with the Acquisition, the "Business Combination"). At the conclusion of the Business Combination, another wholly-owned subsidiary of ENLC, Acacia Natural Gas Corp. I, Inc. ("Acacia"), owned the remaining 50% of the outstanding equity interests in Midstream Holdings. In 2015, Acacia contributed the remaining 50% interest in Midstream Holdings to us in exchange for 68.2 million units of our limited partnership interests in two separate drop down transactions, with 25% contributed in February 2015 and 25% contributed in May 2015 (the "EMH Drop Downs"). After giving effect to the EMH Drop Downs, we own 100% of Midstream Holdings.

We accounted for the EMH Drop Downs as a transfer between entities under common control in accordance with ASC 805, *Business Combinations* ("ASC 805"). As such, the EMH Drop Downs were recorded on our books at historical cost on the date of transfer. The "Transfer of interest in Midstream Holdings" presented in the consolidated statements of changes in partners' equity represents the adjustment to equity due to the recast to offset distributions paid to ENLC for its related ownership during the period January 1, 2015 to May 27, 2015.

In addition, in April 2015, we acquired the Victoria Express Pipeline and related truck terminal and storage assets located in the Eagle Ford Shale in South Texas (VEX"), together with 100% of the voting equity interests (the "VEX interests") in certain entities, from Devon in a drop down transaction (the "VEX Drop Down").

Effective as of January 7, 2016, the Operating Partnership acquired 83.9% of the outstanding equity interests in EnLink Oklahoma T.O., and ENLC acquired the remaining 16.1% equity interests in EnLink Oklahoma T.O. Since we control EnLink Oklahoma T.O., we reflect our ownership in EnLink Oklahoma T.O. on a consolidated basis, and ENLC's ownership is reflected as a non-controlling interest in the respective consolidated financial statements and related disclosures. See "Note 3—Acquisitions" for further discussion.

(b) Nature of Business

We primarily focus on providing midstream energy services, including:

- gathering, compressing, treating, processing, transporting, storing and selling natural gas;
- fractionating, transporting, storing, exporting and selling NGLs; and
- gathering, transporting, stabilizing, storing, trans-loading and selling crude oil and condensate.

Our midstream energy asset network includes approximately 11,000 miles of pipelines, 20 natural gas processing plants with approximately 4.8 Bcf/d of processing capacity, 7 fractionators with approximately 260,000 Bbls/d of fractionation capacity, barge and rail terminals, product storage facilities, purchasing and marketing capabilities, brine disposal wells, a crude oil trucking fleet, and equity investments in certain joint ventures. Our operations are based in the United States, and our sales are derived primarily from domestic customers.

We connect the wells of producers in our market areas to our gathering systems, which consist of networks of pipelines that collect natural gas from points near producing wells and transport it to our processing plants or to larger pipelines for further transmission. We operate processing plants that remove NGLs from the natural gas stream that is transported to the processing plants by our own gathering systems or by third-party pipelines. In conjunction with our gathering and processing business, we may purchase natural gas and NGLs from producers and other supply sources and sell that natural gas or NGLs to utilities, industrial consumers, other markets and pipelines. Our transmission pipelines receive natural gas from our gathering systems and from third-party gathering and transmission systems and deliver natural gas to industrial end-users, utilities and other pipelines.

Our fractionators separate NGLs into separate purity products, including ethane, propane, iso-butane, normal butane and natural gasoline. Our fractionators receive NGLs primarily through our transmission lines that transport NGLs from East Texas and from our South Louisiana processing plants, and our fractionators also have the capability to receive NGLs by truck or rail terminals. We also have agreements pursuant to which third parties transport NGLs from our West Texas and Central Oklahoma operations to our NGL transmission lines that then transport the NGLs to our fractionators. In addition, we have NGL storage capacity to provide storage for customers.

Our crude oil and condensate business includes gathering and transmission via pipelines, barges, rail and trucks, condensate stabilization and brine disposal. We may purchase crude oil and condensate from producers and other supply sources and sell that crude oil and condensate through our terminal facilities that provide market access.

Across our businesses, we primarily earn our fees through various fee-based contractual arrangements, which include stated fee-only contract arrangements or arrangements with fee-based components where we purchase and resell commodities in connection with providing the related service and earn a net margin as our fee. We earn our net margin under our purchase and resell contract arrangements primarily as a result of stated service-related fees that are deducted from the price of the commodities purchased. While our transactions vary in form, the essential element of each transaction is the use of our assets to transport a product or provide a processed product to an end-user or other marketer or pipeline at the tailgate of the plant, barge terminal or pipeline.

(2) Significant Accounting Policies

(a) Basis of Presentation

The accompanying consolidated financial statements have been prepared in accordance with accounting principles generally accepted in the United States of America (“GAAP”) for complete financial statements.

(b) Management’s Use of Estimates

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

(c) Revenue Recognition

We generate the majority of our revenues from midstream energy services, including gathering, transmission, processing, fractionation, storage, condensate stabilization, brine services and marketing, through various contractual arrangements, which include fee-based contract arrangements or arrangements where we purchase and resell commodities in connection with providing the related service and earn a net margin for our fee. While our transactions vary in form, the essential element of each transaction is the use of our assets to transport a product or provide a processed product to an end-user at the tailgate of the plant, barge terminal or pipeline. We reflect revenue as “Product sales” and “Midstream services” revenue on the consolidated statements of operations as follows:

- *Product sales—P*roduct sales represent the sale of natural gas, NGLs, crude oil and condensate where the product is purchased and resold in connection with providing our midstream services as outlined above.

- *Midstream services*—Midstream services represent all other revenue generated as a result of performing our midstream services outlined above.

We recognize revenue for sales or services at the time the natural gas, NGLs, crude oil or condensate are delivered or at the time the service is performed at a fixed or determinable price. We generally accrue one month of sales and the related natural gas, NGL, condensate and crude oil purchases and reverse these accruals when the sales and purchases are invoiced and recorded in the subsequent month. Actual results could differ from the accrual estimates. Except for fixed-fee based arrangements, we act as the principal in these purchase and sale transactions, bearing the risk and reward of ownership, scheduling the transportation of products and assuming credit risk. We account for taxes collected from customers attributable to revenue transactions and remitted to government authorities on a net basis (excluded from revenues).

Certain gathering and processing agreements in our Texas, Oklahoma and Crude and Condensate segments provide for quarterly or annualminimum volume commitments ("MVC" or "MVCs"), including MVCs from Devon from certain of our Barnett Shale assets in North Texas and our Cana plant in Oklahoma. Under these agreements, our customers agree to ship and/or process a minimum volume of production on our systems over an agreed time period. If a customer under such an agreement fails to meet its MVC for a specified period, the customer is obligated to pay a contractually-determined fee based upon the shortfall between actual production volumes and the MVC for that period. Some of these agreements also contain make-up right provisions that allow a customer to utilize gathering or processing fees in excess of the MVC in subsequent periods to offset shortfall amounts in previous periods. We record revenue under MVC contracts during periods of shortfall when it is known that the customer cannot, or will not, make up the deficiency in subsequent periods.

(d) Gas Imbalance Accounting

Quantities of natural gas and NGLs over-delivered or under-delivered related to imbalance agreements are recorded monthly as receivables or payables using weighted average prices at the time of the imbalance. These imbalances are typically settled with deliveries of natural gas or NGLs. We had imbalance payables of $7.3 million and $7.1 million at December 31, 2017 and 2016, respectively, which approximate the fair value of these imbalances. We had imbalance receivables of$5.8 million and $3.9 million at December 31, 2017 and 2016, respectively, which are carried at the lower of cost or market value. Imbalance receivables and imbalance payables are included in the line items "Accrued revenue and other" and "Accrued gas, NGLs, condensate and crude oil purchases," respectively, on the consolidated balance sheets.

(e) Cash and Cash Equivalents

We consider all highly liquid investments with an original maturity of three months or less to be cash equivalents.

(f) Income Taxes

Certain of our operations are subject to income taxes assessed by the federal and various state jurisdictions in the U.S. Additionally, certain of our operations are subject to tax assessed by the state of Texas that is computed based on modified gross margin as defined by the State of Texas. The Texas franchise tax is presented as income tax expense in the accompanying statements of operations.

We account for deferred income taxes related to the federal and state jurisdictions using the asset and liability method. Under this method, deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of assets and liabilities and their respective tax bases. Deferred tax assets are also recognized for the future tax benefits attributable to the expected utilization of existing tax net operating loss carryforwards and other types of carryforwards. If the future utilization of some portion of carryforwards is determined to be unlikely, a valuation allowance is provided to reduce the recorded tax benefits from such assets. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences and carryforwards are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in income in the period that includes the enactment date. In the event interest or penalties are incurred with respect to income tax matters, our policy will be to include such items in income tax expense.

(g) Natural Gas, Natural Gas Liquids, Crude Oil and Condensate Inventory

Our inventories of products consist of natural gas, NGLs, crude oil and condensate. We report these assets at the lower of cost or market value which is determined by using the first-in, first-out method.

(h) Property and Equipment

Property and equipment are stated at historical cost less accumulated depreciation. Assets acquired in a business combination are recorded at fair value. Repairs and maintenance are charged against income when incurred. Renewals and betterments, which extend the useful life of the properties, are capitalized. Interest costs for material projects are capitalized to property and equipment during the period the assets are undergoing preparation for intended use.

The components of property and equipment are as follows (in millions):

	Year Ended December 31,	
	2017	2016
Transmission assets	$ 1,338.7	$ 1,191.7
Gathering systems	4,040.9	3,530.9
Gas processing plants	3,401.8	3,163.0
Other property and equipment	157.8	149.5
Construction in process	180.8	345.7
Property and equipment	$ 9,120.0	$ 8,380.8
Accumulated depreciation	(2,533.0)	(2,124.1)
Property and equipment, net of accumulated depreciation	$ 6,587.0	$ 6,256.7

Depreciation is calculated using the straight-line method based on the estimated useful life of each asset, as follows:

	Useful Lives
Transmission assets	20 - 25 years
Gathering systems	20 - 25 years
Gas processing plants	20 - 25 years
Other property and equipment	3 - 15 years

Depreciation expense of $418.2 million, $386.9 million and $331.3 million was recorded for the years ended December 31, 2017, 2016 and 2015, respectively.

Gain or Loss on Disposition. Upon the disposition or retirement of property and equipment, any gain or loss is recognized in operating income in the statement of operations. For the year ended December 31, 2017, we disposed of assets with a net book value of $8.4 million, and these dispositions primarily related to the retirement of compressors due to fire damage. This decrease in book value was offset by $6.1 million in expected insurance settlements and $2.3 million of proceeds from the sale of property, resulting in no gain or loss on disposition of assets in the consolidated statement of operations for the year ended December 31, 2017.

For the year ended December 31, 2016, we retired or sold net property and equipment of $106.6 million, which was offset by $0.3 million of insurance settlements and $93.1 million of proceeds from the sale of property, resulting in a loss on disposition of assets of $13.2 million. The loss on disposition of assets primarily related to the sale of the North Texas Pipeline System (“NPTL”), a 140-mile natural gas transportation pipeline, that resulted in net proceeds of $84.6 million and a loss on sale of $13.4 million.

For the year ended December 31, 2015, we retired net property and equipment of $5.1 million, which was offset by $2.9 million of insurance settlements and $1.0 million of proceeds from the sale of property. This resulted in a loss on disposition of assets of $1.2 million, which primarily relates to the retirement of a compressor due to fire damage. Additionally, we collected

$2.4 million of business interruption proceeds from our insurance carrier that was presented in the “Midstream services” revenue line item in the consolidated statement of operations for the year ended December 31, 2015.

Impairment Review. In accordance with ASC 360, *Property, Plant and Equipment*, we evaluate long-lived assets of identifiable business activities for potential impairment whenever events or changes in circumstances indicate that their carrying value may not be recoverable. The carrying amount of a long-lived asset is not recoverable when it exceeds the undiscounted sum of the future cash flows expected to result from the use and eventual disposition of the asset. Estimates of expected future cash flows represent management’s best estimate based on reasonable and supportable assumptions. When the carrying amount of a long-lived asset is not recoverable, an impairment loss is recognized equal to the excess of the asset’s carrying value over its fair value.

When determining whether impairment of our long-lived assets has occurred, we must estimate the undiscounted cash flows attributable to the asset. Our estimate of cash flows is based on assumptions regarding:

- the future fee-based rate of new business or contract renewals;
- the purchase and resale margins on natural gas, NGLs, crude oil and condensate;
- the volume of natural gas, NGLs, crude oil and condensate available to the asset;
- markets available to the asset;
- operating expenses; and
- future natural gas, NGLs, crude oil and condensate prices.

The amount of availability of natural gas, NGLs, crude oil and condensate to an asset is sometimes based on assumptions regarding future drilling activity, which may be dependent in part on natural gas, NGL, crude oil and condensate prices. Projections of natural gas, NGL, crude oil and condensate volumes and future commodity prices are inherently subjective and contingent upon a number of variable factors, including but not limited to:

- changes in general economic conditions in regions in which our markets are located;
- the availability and prices of natural gas, NGLs, crude oil and condensate supply;
- our ability to negotiate favorable sales agreements;
- the risks that natural gas, NGLs, crude oil and condensate exploration and production activities will not occur or be successful;
- our dependence on certain significant customers, producers and transporters of natural gas, NGLs, crude oil and condensate; and
- competition from other midstream companies, including major energy companies.

For the year ended December 31, 2017, we recognized impairments on property and equipment of $17.1 million, which related to the carrying values of rights-of-way that we are no longer using and an abandoned brine disposal well. For the year ended December 31, 2015, we recognized a $12.1 million impairment on property and equipment, primarily related to costs associated with the cancellation of various capital projects in our Texas, Louisiana, and Crude and Condensate segments.

(i) Comprehensive Income (Loss)

Comprehensive income (loss) is composed of net income (loss), which consists of the effective portion of gains or losses on derivative financial instruments that qualify as cash flow hedges pursuant to ASC 815, *Derivatives and Hedging* (“ASC 815”). For the year ended December 31, 2017, we reclassified an immaterial amount of losses from accumulated other comprehensive income (loss) to earnings. For additional information, see “Note 12—Derivatives*.”*

(j) Equity Method of Accounting

We account for investments where we do not control the investment but have the ability to exercise significant influence using the equity method of accounting. Under this method, unconsolidated affiliate investments are initially carried at the acquisition cost, increased by our proportionate share of the investee’s net income and by contributions made, and decreased by our proportionate share of the investee’s net losses and by distributions received.

We evaluate our unconsolidated affiliate investments for potential impairment whenever events or changes in circumstances indicate that the carrying amount of the investments may not be recoverable. We recognize impairments of our investments as a loss from unconsolidated affiliates on our consolidated statements of operations. For additional information, see "Note 10—Investment in Unconsolidated Affiliates."

(k) Goodwill

Goodwill is the cost of an acquisition less the fair value of the net identifiable assets of the acquired business. We evaluate goodwill for impairment annually as of October 31 and whenever events or changes in circumstances indicate it is more likely than not that the fair value of a reporting unit is less than its carrying amount. For additional information regarding our assessment of goodwill for impairment, see "Note 4—Goodwill and Intangible Assets."

(l) Intangible Assets

Intangible assets associated with customer relationships are amortized on a straight-line basis over the expected period of benefits of the customer relationships, which range from ten to twenty years. For additional information regarding our intangible assets, including our assessment of intangible assets for impairment, see "Note 4—Goodwill and Intangible Assets."

(m) Asset Retirement Obligations

We recognize liabilities for retirement obligations associated with our pipelines and processing and fractionation facilities. Such liabilities are recognized when there is a legal obligation associated with the retirement of the assets and the amount can be reasonably estimated. The initial measurement of an asset retirement obligation is recorded as a liability at its fair value, with an offsetting asset retirement cost recorded as an increase to the associated property and equipment. If the fair value of a recorded asset retirement obligation changes, a revision is recorded to both the asset retirement obligation and the asset retirement cost. Our retirement obligations include estimated environmental remediation costs that arise from normal operations and are associated with the retirement of the long-lived assets. The asset retirement cost is depreciated using the straight-line depreciation method similar to that used for the associated property and equipment. For additional information, see "Note 9—Asset Retirement Obligations."

(n) Other Long-Term Liabilities

Other current and long-term liabilities include a liability related to an onerous performance obligation assumed in the Business Combination of $26.9 million and $44.8 million as of December 31, 2017 and 2016, respectively. We have one delivery contract that requires us to deliver a specified volume of gas each month at an indexed base price with a term to mid-2019. We realize a loss on the delivery of gas under this contract each month based on current prices. The fair value of this onerous performance obligation was based on forecasted discounted cash obligations in excess of market under this gas delivery contract in March 2014. The liability is reduced each month as delivery is made over the remaining life of the contract with an offsetting reduction in purchased gas costs.

(o) Derivatives

We use derivative instruments to hedge against changes in cash flows related to product price. We generally determine the fair value of swap contracts based on the difference between the derivative's fixed contract price and the underlying market price at the determination date. The asset or liability related to the derivative instruments is recorded on the balance sheet at the fair value of derivative assets or liabilities in accordance with ASC 815, *Derivatives and Hedging* ("ASC 815"). Changes in fair value of derivative instruments are recorded in gain or loss on derivative activity in the period of change.

Realized gains and losses on commodity-related derivatives are recorded as gain or loss on derivative activity within revenues in the consolidated statements of operations in the period incurred. Settlements of derivatives are included in cash flows from operating activities.

We periodically enter into interest rate swaps in connection with new debt issuances. During the debt issuance process, we are exposed to variability in future long-term debt interest payments that may result from changes in the benchmark interest rate (commonly the U.S. Treasury yield) prior to the debt being issued. In order to hedge this variability, we enter into interest rate swaps to effectively lock in the benchmark interest rate at the inception of the swap. Prior to 2017, we did not designate interest rate swaps as hedges and, therefore, included the associated settlement gains and losses as interest expense on the consolidated statements of operations.

In May 2017, we entered into an interest rate swap in connection with the issuance of our senior unsecured notes due June 1, 2047 (the "2047 Notes"). In accordance with ASC 815, we designated this swap as a cash flow hedge. Upon settlement of the interest rate swap in May 2017, we recorded the associated $2.2 million settlement loss in accumulated other comprehensive loss on the consolidated balance sheets. We will amortize the settlement loss into interest expense on the consolidated statements of operations over the term of the 2047 Notes.

For additional information, see "Note 12—Derivatives."

(p) Concentrations of Credit Risk

Financial instruments, which potentially subject us to concentrations of credit risk, consist primarily of trade accounts receivable and commodity financial instruments. Management believes the risk is limited, other than our exposure to Devon discussed below, since our customers represent a broad and diverse group of energy marketers and end users. In addition, we continually monitor and review the credit exposure of our marketing counter-parties, and letters of credit or other appropriate security are obtained when considered necessary to limit the risk of loss. We record reserves for uncollectible accounts on a specific identification basis since there is not a large volume of late paying customers. We had a reserve for uncollectible receivables of $0.3 million and $0.1 million as of December 31, 2017 and 2016, respectively.

For the years ended December 31, 2017, 2016 and 2015, we had two customers that individually represented greater than 10.0% of our consolidated revenues. Dow Hydrocarbons & Resources LLC ("Dow Hydrocarbons") is located in the Louisiana segment and represented 11.2%, 10.8% and 11.7% of our consolidated revenues for the years ended December 31, 2017, 2016 and 2015, respectively. The affiliate transactions with Devon represented 14.4%, 18.5% and 16.6% of our consolidated revenues for the years ended December 31, 2017, 2016 and 2015, respectively. Devon and Dow Hydrocarbons represent a significant percentage of revenues, and the loss of either as a customer would have a material adverse impact on our results of operations because the gross operating margin received from transactions with these customers is material to us.

(q) Environmental Costs

Environmental expenditures are expensed or capitalized depending on the nature of the expenditures and the future economic benefit. Expenditures that relate to an existing condition caused by past operations that do not contribute to current or future revenue generation are expensed. Liabilities for these expenditures are recorded on an undiscounted basis (or a discounted basis when the obligation can be settled at fixed and determinable amounts) when environmental assessments or clean-ups are probable and the costs can be reasonably estimated. Environmental expenditures were $0.9 million and $3.5 million for the years ended December 31, 2017 and 2015. For the year ended December 31, 2016, such expenditures were not material.

(r) Unit-Based Awards

We recognize compensation cost related to all unit-based awards in our consolidated financial statements in accordance with ASC 718, *Compensation—Stock Compensation* ("ASC 718"). We and ENLC each have similar unit-based payment plans for employees. Unit-based compensation associated with ENLC's unit-based compensation plans awarded to directors, officers and employees of our general partner are recorded by us since ENLC has no substantial or managed operating activities other than its interests in us and EnLink Oklahoma T.O. For additional information, see "Note 11—Employee Incentive Plans."

(s) Commitments and Contingencies

Liabilities for loss contingencies arising from claims, assessments, litigation or other sources are recorded when it is probable that a liability has been incurred and the amount can be reasonably estimated. For additional information, see "Note 14—Commitments and Contingencies."

(t) Debt Issuance Costs

Costs incurred in connection with the issuance of long-term debt are deferred and recorded as interest expense over the term of the related debt. Gains or losses on debt repurchases, redemptions and debt extinguishments include any associated unamortized debt issue costs. Unamortized debt issuance costs totaling $25.9 million and $24.1 million as of December 31, 2017 and 2016, respectively, are included in "Long-term debt" on the consolidated balance sheets as a direct reduction from the carrying amount of long-term debt. Debt issuance costs are amortized into interest expense using the straight-line method over the term of the related debt issuance.

(u) Legal Costs Expected to be Incurred in Connection with a Loss Contingency

Legal costs incurred in connection with a loss contingency are expensed as incurred.

(v) Redeemable Non-Controlling Interest

Non-controlling interests that contain an option for the non-controlling interest holder to require us to buy out such interests for cash are considered to be redeemable non-controlling interests because the redemption feature is not deemed to be a freestanding financial instrument and because the redemption is not solely within our control. Redeemable non-controlling interest is not considered to be a component of partners' equity and is reported as temporary equity in the mezzanine section on the consolidated balance sheets. The amount recorded as redeemable non-controlling interest at each balance sheet date is the greater of the redemption value and the carrying value of the redeemable non-controlling interest (the initial carrying value increased or decreased for the non-controlling interest holder's share of net income or loss and distributions).

(w) Adopted Accounting Standards

In March 2016, the Financial Accounting Standards Board ("FASB") issued ASU 2016-09, *Improvements to Employee Share-Based Payment Accounting, which amends ASC Topic 718, Compensation — Stock Compensation* ("ASU 2016-09"), which simplifies several aspects related to the accounting for share-based payment transactions. Effective January 1, 2017, we adopted ASU 2016-09. We prospectively adopted the guidance that requires excess tax benefits and deficiencies be recognized on the income statement. The cash flow statement guidance requires the presentation of excess tax benefits and deficiencies as an operating activity and the presentation of cash paid by an employer when directly withholding shares for tax-withholding purposes as a financing activity, and this treatment is consistent with our historical accounting treatment. Finally, we elected to estimate the number of awards that are expected to vest, which is consistent with our historical accounting treatment. The adoption of ASU 2016-09 did not materially affect the consolidated statement of operations for the year ended December 31, 2017.

In January 2017, the FASB issued ASU 2017-04, *Intangibles—Goodwill and Other (Topic 350)— Simplifying the Test for Goodwill Impairment* ("ASU 2017-04"). ASU 2017-04 simplifies the accounting for goodwill impairments by eliminating the requirement to compare the implied fair value of goodwill with its carrying amount as part of step two of the goodwill impairment test referenced in ASC 350. As a result, an entity should perform its annual or interim goodwill impairment test by comparing the fair value of a reporting unit with its carrying amount. An impairment charge should be recognized for the amount by which the carrying amount exceeds the reporting unit's fair value. However, the impairment loss recognized should not exceed the total amount of goodwill allocated to that reporting unit. ASU 2017-04 is effective for annual reporting periods beginning after December 15, 2019, including any interim impairment tests within those annual periods, with early application permitted for interim or annual goodwill tests performed on testing dates after January 1, 2017. In January 2017, we elected to early adopt ASU 2017-04, and the adoption had no impact on our consolidated financial statements.

(x) Accounting Standards to be Adopted in Future Periods

In February 2016, the FASB issued ASU 2016-02, *Leases (Topic 842)—Amendments to the FASB Accounting Standards Codification* ("ASU 2016-02"). Lessees will need to recognize virtually all of their leases on the balance sheet by recording a right-of-use asset and lease liability. Lessor accounting is similar to the current model, but updated to align with certain changes to the lessee model and the new revenue recognition standard. Existing sale-leaseback guidance is replaced with a new model applicable to both lessees and lessors. Additional revisions have been made to embedded leases, reassessment requirements and lease term assessments including variable lease payment, discount rate and lease incentives. ASU 2016-02 is effective for annual reporting periods beginning after December 15, 2018, including interim periods within those annual periods. Early adoption is permitted. Entities are required to adopt ASU 2016-02 using a modified retrospective transition. We are currently assessing the impact of adopting ASU 2016-02. This assessment includes the gathering and evaluation of our current lease contracts and the analysis of contracts that may contain lease components. While we cannot currently estimate the quantitative effect that ASU 2016-02 will have on our consolidated financial statements, the adoption of ASU 2016-02 will increase our asset and liability balances on the consolidated balance sheets due to the required recognition of right-of-use assets and corresponding lease liabilities for all lease obligations that are currently classified as operating leases. In addition, there are industry-specific concerns with the implementation of ASU 2016-02 that will require further evaluation before we are able to fully assess the impact on our consolidated financial statements.

In May 2014, the FASB issued ASU 2014-09, *Revenue from Contracts with Customers* ("ASU 2014-09"), which established ASC Topic 606, Revenue from Contracts with Customers ("ASC 606"). ASC 606 will replace existing revenue recognition requirements in GAAP and will require entities to recognize revenue at an amount that reflects the consideration to which they expect to be entitled in exchange for transferring goods or services to a customer. ASC 606 will also require significantly expanded disclosures containing qualitative and quantitative information regarding the nature, amount, timing and uncertainty of revenue and cash flows arising from contracts with customers. In May 2016, the FASB issued ASU 2016-12, *Revenue from Contracts with Customers (Topic 606): Narrow-Scope Improvements and Practical Expedients* ("ASU 2016-12"), which updated ASU 2014-09. ASU 2016-12 clarifies certain core recognition principles, including collectability, sales tax presentation, noncash consideration, contract modifications and completed contracts at transition and disclosures no longer required if the full retrospective transition method is adopted. ASU 2014-09 and ASU 2016-12 are effective for annual reporting periods beginning after December 15, 2017, including interim periods within those annual periods, and are to be applied using the modified retrospective or full retrospective transition methods, with early application permitted for annual reporting periods beginning after December 15, 2016. We will adopt ASC 606 using the modified retrospective method for annual and interim reporting periods beginning January 1, 2018.

We have aggregated and reviewed our contracts that are within the scope of ASC 606. Based on our evaluation to date, we do not anticipate the adoption of ASC 606 will have a material impact on our results of operations, financial condition or cash flows. However, ASC 606 will affect how certain transactions are recorded in the financial statements. For each contract with a customer, we will need to identify our performance obligations, of which the identification includes careful evaluation of when control and the economic benefits of the commodities transfer to us. The evaluation of control will change the way we account for certain transactions, specifically those in which there is both a commodity purchase component and a service component. For contracts where control of commodities transfers to us before we perform our services, we generally have no performance obligation for our services, and accordingly, we will not consider these revenue-generating contracts. Based on that determination, all fees or fee-equivalent deductions stated in such contracts would reduce the cost to purchase commodities. Alternatively, for contracts where control of commodities transfers to us after we perform our services, we have performance obligations for our services. Accordingly, we will consider the satisfaction of these performance obligations as revenue-generating and recognize these fees as midstream service revenues at the time we satisfy our performance obligations. For contracts where control of commodities never transfers to us and we simply earn a fee for our services, we will recognize these fees as midstream services revenues at the time we satisfy our performance obligations. Based on our review of our performance obligations in our contracts with customers, we will change the statement of operations classification for certain transactions from revenue to cost of sales or from cost of sales to revenue. We estimate that the reclassification of revenues and costs will result in a net decrease in revenue of approximately 6-10%, although this estimate is based on historical information and could change based on commodity prices going forward. This reclassification of revenues and costs will have no effect on operating income and gross operating margin.

Our performance obligations represent promises to transfer a series of distinct goods or services that are satisfied over time and that are substantially the same to the customer. As permitted by ASC 606, we will utilize the practical expedient that allows an entity to recognize revenue in the amount to which the entity has a right to invoice, if an entity has a right to consideration from a customer in an amount that corresponds directly with the value to the customer of the entity's performance completed to date. Accordingly, we will continue to recognize revenue at the time commodities are delivered or services are performed, so ASC 606 will not significantly affect the timing of revenue and expense recognition on our statements of operations.

Based on the disclosure requirements of ASC 606, upon adoption, we expect to provide expanded disclosures relating to our revenue recognition policies and how these relate to our revenue-generating contractual performance obligations. In addition, we expect to present revenues disaggregated based on the type of good or service in order to more fully depict the nature of our revenues.

(3) Acquisitions

LPC Acquisition

On January 31, 2015, we acquired 100% of the voting equity interests of LPC Crude Oil Marketing LLC (“LPC”), which has crude oil gathering, transportation and marketing operations in the Permian Basin, for approximately $108.1 million. The transaction was accounted for using the acquisition method.

The following table presents the fair value of the identified assets received and liabilities assumed at the acquisition date (in millions):

Purchase Price Allocation:		
Assets acquired:		
Current assets (including $21.1 million in cash)	$	107.4
Property and equipment		29.8
Intangibles		43.2
Goodwill		29.6
Liabilities assumed:		
Current liabilities		(97.9)
Deferred tax liability		(4.0)
Total identifiable net assets	$	108.1

We recognized intangible assets related to customer relationships and trade name. The acquired intangible assets related to customer relationships are amortized on a straight-line basis over the estimated customer life of approximately 10 years. Goodwill recognized from the acquisition primarily related to the value created from additional growth opportunities and greater operating leverage in the Permian Basin. All such goodwill was allocated to our Crude and Condensate segment and was subsequently impaired during the year ended December 31, 2016.

We incurred $0.3 million of direct transaction costs for the year ended December 31, 2015. These costs are included in general and administrative costs in the accompanying consolidated statements of operations.

For the period from January 31, 2015 to December 31, 2015, we recognized $1.1 billion of revenues and $0.9 million of net income related to the assets acquired.

Coronado Acquisition

On March 16, 2015, we acquired 100% of the voting equity interests in Coronado Midstream Holdings LLC (“Coronado”), which owns natural gas gathering and processing facilities in the Permian Basin, for approximately $600.3 million. The purchase price consisted of $240.3 million in cash, 6,704,285 of our common units and 6,704,285 of our Class C Common Units.

The following table presents the fair value of the identified assets received and liabilities assumed at the acquisition date (in millions):

Purchase Price Allocation:		
Assets acquired:		
Current assets (including $1.4 million in cash)	$	20.8
Property and equipment		302.1
Intangibles		281.0
Goodwill		18.7
Liabilities assumed:		
Current liabilities		(22.3)
Total identifiable net assets	$	600.3

We recognized intangible assets related to customer relationships. The acquired intangible assets are amortized on a straight-line basis over the estimated customer life of approximately 10 to 20 years. Goodwill recognized from the acquisition primarily relates to the value created from additional growth opportunities and greater operating leverage in the Permian Basin. All such goodwill is allocated to our Texas segment.

We incurred $3.1 million of direct transaction costs for the year ended December 31, 2015. These costs are included in general and administrative expenses in the accompanying consolidated statements of operations.

For the period from March 16, 2015 to December 31, 2015, we recognized$182.0 million of revenues and $14.2 million of net loss related to the assets acquired.

Matador Acquisition

On October 1, 2015, we acquired 100% of the voting equity interests in a subsidiary of Matador Resources Company (“Matador”), which has gathering and processing assets operations in the Delaware Basin, for approximately $141.3 million. The transaction was accounted for using the acquisition method.

The following table presents the fair value of the identified assets received and liabilities assumed at the acquisition date (in millions):

Purchase Price Allocation:		
Assets acquired:		
Current assets	$	1.1
Property and equipment		35.5
Intangibles		98.8
Goodwill		10.7
Liabilities assumed:		
Current liabilities		(4.8)
Total identifiable net assets	$	141.3

We recognized intangible assets related to customer relationships. The acquired intangible assets are amortized on a straight-line basis over the estimated customer 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 Permian Basin. All such goodwill is allocated to our Texas segment.

We incurred $0.1 million of direct transaction costs for the year ended December 31, 2015. These costs are included in general and administrative expenses in the accompanying consolidated statements of operations.

For the period from October 1, 2015 to December 31, 2015, we recognized $5.6 million of revenues and $0.7 million of net loss related to the assets acquired.

Deadwood Acquisition

Prior to November 2015, we co-owned the Deadwood natural gas processing plant with a subsidiary of Apache Corporation ("Apache"). On November 16, 2015, we acquired Apache's 50% ownership interest in the Deadwood natural gas processing facility for approximately $40.1 million, all of which is considered property and equipment. The transaction was accounted for using the acquisition method. Direct transaction costs attributable to this acquisition were less than $0.1 million.

For the period from November 16, 2015 to December 31, 2015, we recognized $3.5 million of revenues and $1.3 million of net income related to the assets acquired.

VEX Pipeline Drop Down

On April 1, 2015, we acquired VEX, located in the Eagle Ford Shale in South Texas, together with 100% of the voting equity interests in certain entities, from Devon in the VEX Drop Down. The aggregate consideration paid by us consisted of $166.7 million in cash, 338,159 common units representing our limited partner interests with an aggregate value of approximately $9.0 million and our assumption of up to $40.0 million in certain construction costs related to VEX. The acquisition has been accounted for as an acquisition under common control under ASC 805, resulting in the retrospective adjustment of our prior results. As such, the VEX interests were recorded on our books at historical cost on the date of transfer of $131.0 million. The difference between the historical cost of the net assets and consideration given was $35.7 million and is recognized as a distribution to Devon. Construction costs paid by Devon during the first quarter of 2015 totaling $25.6 million are reflected as contributions from Devon in our consolidated statements of changes in partners' equity and consolidated statements of cash flows for the year ended December 31, 2015.

Pro Forma of Acquisitions for the Years Ended 2015

The following unaudited pro forma condensed financial information (in millions, except for per unit data) for the year ended December 31, 2015 gives effect to the January 2015 LPC acquisition, March 2015 Coronado acquisition, October 2015 Matador acquisition and the VEX Drop Down as if they had occurred on January 1, 2015. The unaudited pro forma condensed financial information has been included for comparative purposes only and is not necessarily indicative of the results that might have occurred had the transactions taken place on the dates indicated and is not intended to be a projection of future results.

	Year Ended December 31, 2015
Pro forma total revenues	$ 4,585.5
Pro forma net loss	$ (1,381.8)
Pro forma net loss attributable to EnLink Midstream Partners, LP	$ (1,381.4)
Pro forma net loss per common unit:	
Basic	$ (4.63)
Diluted	$ (4.63)

EnLink Oklahoma T.O. Acquisition

On January 7, 2016, ENLK and ENLC acquired an 83.9% and 16.1% voting interest, respectively, in EnLink Oklahoma T.O. for aggregate consideration of approximately $1.4 billion. The first installment of $1.02 billion for the acquisition was paid at closing. The second and final installments, each equal to $250.0 million, were paid in January 2017 and January 2018, respectively.

The first installment of approximately $1.02 billion was funded by (a) approximately $783.6 million in cash paid by ENLK, which was primarily derived from the issuance of Series B Cumulative Convertible Preferred Units ("Series B Preferred Units"), (b) 15,564,009 common units representing limited liability company interests in ENLC issued directly by ENLC and (c) approximately $22.2 million in cash paid by ENLC. The transaction was accounted for using the acquisition method.

The following table presents the considerations ENLK and ENLC paid and the fair value of the identified assets received and liabilities assumed at the acquisition date (in millions):

Consideration:		
Cash	$	783.6
Total installment payable, net of discount of $79.1 million		420.9
Contribution from ENLC		237.1
Total consideration	$	1,441.6
Purchase Price Allocation:		
Assets acquired:		
Current assets (including $12.8 million in cash)	$	23.0
Property and equipment		406.1
Intangibles		1,051.3
Liabilities assumed:		
Current liabilities		(38.8)
Total identifiable net assets	$	1,441.6

The fair value of assets acquired and liabilities assumed are based on inputs that are not observable in the market and thus represent Level 3 inputs. We recognized intangible assets related to customer relationships and determined their fair value using the income approach. The acquired intangible assets are amortized on a straight-line basis over the estimated customer life of approximately 15 years.

We incurred a total of $3.7 million and $0.4 million of direct transaction costs for the year ended December 31, 2016 and December 31, 2015, respectively. These costs are incurred in general and administrative costs in the accompanying consolidated statements of operations.

For the period from January 7, 2016 to December 31, 2016, we recognized $246.1 million of revenues and $34.1 million of net loss, of which $5.5 million is attributable to non-controlling interests, related to the assets acquired.

Pro Forma of the EnLink Oklahoma T.O. Acquisition

The following unaudited pro forma condensed financial information (in millions, except for per unit data) for the year ended December 31, 2016 and 2015 gives effect to the January 2016 acquisition of EnLink Oklahoma T.O as if it had occurred on January 1, 2015. The unaudited pro forma condensed financial information has been included for comparative purposes only and is not necessarily indicative of the results that might have occurred had the transaction taken place on the dates indicated and is not intended to be a projection of future results.

	Year Ended December 31,			
	2016		**2015**	
Pro forma total revenues	$	4,254.4	$	4,514.3
Pro forma net loss	$	(574.1)	$	(1,454.5)
Pro forma net loss attributable to EnLink Midstream Partners, LP	$	(565.8)	$	(1,441.8)
Pro forma net loss per common unit:				
Basic	$	(2.03)	$	(5.10)
Diluted	$	(2.03)	$	(5.10)

(4) Goodwill and Intangible Assets

Goodwill

Goodwill is the cost of an acquisition less the fair value of the net identifiable assets of the acquired business.The fair value of goodwill is based on inputs that are not observable in the market and thus represent Level 3 inputs.

The table below provides a summary of our change in carrying amount of goodwill (in millions) for the year ended December 31, 2016, by assigned reporting unit:

	Texas	Oklahoma	Crude and Condensate	Totals
Year Ended December 31, 2016				
Balance, beginning of period	$ 703.5	$ 190.3	$ 93.2	$ 987.0
Impairment	(473.1)	—	(93.2)	(566.3)
Acquisition adjustment	1.6	—	—	1.6
Balance, end of period	$ 232.0	$ 190.3	$ —	$ 422.3

For the year ended December 31, 2017, there were no changes to the carrying amount of goodwill.

We evaluate goodwill for impairment annually as of October 31 and whenever events or changes in circumstances indicate it is more likely than not that the fair value of a reporting unit is less than its carrying amount. We first assess qualitative factors to evaluate whether it is more likely than not that the fair value of a reporting unit is less than its carrying amount as the basis for determining whether it is necessary to perform a goodwill impairment test. We may elect to perform a goodwill impairment test without completing a qualitative assessment.

We perform our goodwill assessments at the reporting unit level for all reporting units. We use a discounted cash flow analysis to perform the assessments. Key assumptions in the analysis include the use of an appropriate discount rate, terminal year multiples and estimated future cash flows, including volume and price forecasts and estimated operating and general and administrative costs. In estimating cash flows, we incorporate current and historical market and financial information, among other factors. Impairment determinations involve significant assumptions and judgments, and differing assumptions regarding any of these inputs could have a significant effect on the various valuations. If actual results are not consistent with our assumptions and estimates, or our assumptions and estimates change due to new information, we may be exposed to goodwill impairment charges, which would be recognized in the period in which the carrying value exceeds fair value.

Prior to January 2017, if a goodwill impairment test was elected or required, we performed a two-step goodwill impairment test. The first step involved comparing the fair value of the reporting unit to its carrying amount. If the carrying amount of a reporting unit exceeded its fair value, the second step of the process involved comparing the implied fair value to the carrying value of the goodwill for that reporting unit. If the carrying value of the goodwill of a reporting unit exceeded the implied fair value of that goodwill, the excess of the carrying value over the implied fair value was recognized as an impairment loss.

Effective January 2017, we elected to early adopt ASU 2017-04,*Intangibles—Goodwill and Other (Topic 350)— Simplifying the Test for Goodwill Impairment*, which simplified the accounting for goodwill impairments by eliminating the requirement to compare the implied fair value of goodwill with its carrying amount as part of step two of the goodwill impairment test referenced in ASC 350. Therefore, our annual impairment test as of October 31, 2017 was performed according to ASU 2017-04.

Impairment Analysis for the Year Ended December 31, 2015

During the third quarter of 2015, we determined that sustained weakness in the overall energy sector, driven by low commodity prices together with a decline in our unit price, caused a change in circumstances warranting an interim impairment test. We also performed our annual impairment analysis during the fourth quarter of 2015. Although our established annual effective date for this goodwill analysis is October 31, we updated the effective date for this impairment analysis for the 2015 annual period to December 31, 2015 due to continued declines in commodity prices and our unit price during the fourth quarter of 2015.

Using the fair value approaches described above, in step one of the goodwill impairment test, we determined that the estimated fair values of our Louisiana, Texas and Crude and Condensate reporting units were less than their carrying amounts, primarily related to commodity prices, volume forecasts and discount rates. Based on that determination, we performed the second step of the goodwill impairment test by measuring the amount of impairment loss and allocating the estimated fair value of the reporting unit among all of the assets and liabilities of the reporting unit as if the reporting unit had been acquired in a business combination. Based on this analysis, a goodwill impairment loss for our Louisiana, Texas, and Crude and Condensate reporting units in the amount of $1,328.2 million was recognized for the year ended December 31, 2015 and is included as an impairment loss in the consolidated statement of operations.

We concluded that the fair value of goodwill for our Oklahoma reporting unit exceeded its carrying value, and the amount of goodwill disclosed on the consolidated balance sheet associated with this reporting unit was recoverable. Therefore, no goodwill impairment was identified or recorded for this reporting unit as a result of our annual goodwill assessment.

Impairment Analysis for the Year Ended December 31, 2016

During February 2016, we determined that continued further weakness in the overall energy sector, driven by low commodity prices together with a further decline in our unit price subsequent to year-end, caused a change in circumstances warranting an interim impairment test. Based on these triggering events, we performed a goodwill impairment analysis in the first quarter of 2016 on all reporting units. Based on this analysis, a goodwill impairment loss for our Texas and Crude and Condensate reporting units in the amount of $566.3 million was recognized in the first quarter of 2016 and is included as an impairment loss in the consolidated statement of operations for the year ended December 31, 2016.

We concluded that the fair value of our Oklahoma reporting unit exceeded its carrying value, and the amount of goodwill disclosed on the consolidated balance sheet associated with this reporting unit was recoverable. Therefore, no goodwill impairment was identified or recorded for this reporting unit as a result of our goodwill impairment analysis.

During our annual impairment test for 2016 performed as of October 31, 2016, we determined that no further impairments were required for the year ended December 31, 2016.

Impairment Analysis for the Year Ended December 31, 2017

During our annual impairment test for 2017 performed as of October 31, 2017, we determined that no impairments were required for the year ended December 31, 2017. The estimated fair value of our reporting units may be impacted in the future by a decline in our unit price or a prolonged period of lower commodity prices which may adversely affect our estimate of future cash flows, both of which could result in future goodwill impairment charges for our reporting units.

Intangible Assets

Intangible assets associated with customer relationships are amortized on a straight-line basis over the expected period of benefits of the customer relationships, which range from 10 to 20 years.

The following table represents our change in carrying value of intangible assets for the periods stated (in millions):

	Gross Carrying Amount	Accumulated Amortization	Net Carrying Amount
Year Ended December 31, 2017			
Customer relationships, beginning of period	$ 1,795.8	$ (171.6)	$ 1,624.2
Amortization expense	—	(127.1)	(127.1)
Customer relationships, end of period	$ 1,795.8	$ (298.7)	$ 1,497.1
Year Ended December 31, 2016			
Customer relationships, beginning of period	$ 744.5	$ (54.6)	$ 689.9
Acquisitions	1,051.3	—	1,051.3
Amortization expense	—	(117.0)	(117.0)
Customer relationships, end of period	$ 1,795.8	$ (171.6)	$ 1,624.2

For 2016 and 2015, we reviewed our various assets groups for impairment due to the triggering events described in the goodwill impairment analysis above.We utilized Level 3 fair value measurements in our impairment analysis, which included discounted cash flow assumptions by management consistent with those utilized in our goodwill impairment analysis. During 2016, the undiscounted cash flows of our assets exceeded their carrying values, and no impairment was recorded. During 2015, the undiscounted cash flows related to one of our asset groups in the Crude and Condensate segment were not in excess of its related carrying value. We estimated the fair value of this reporting unit and determined the fair values of certain intangible assets were not in excess of their carrying values. This resulted in a $223.1 million impairment of intangible assets in our Crude and Condensate segment, and this non-cash impairment charge was included as an impairment loss on the consolidated statement of operations for the year ended December 31, 2015. For the year ended December 31, 2017, we determined that no triggering events existed that would indicate an impairment of our intangibles assets.

The weighted average amortization period for intangible assets is 15.0 years. Amortization expense was approximately $127.1 million, $117.0 million, and $56.0 million for the years ended December 31, 2017, 2016 and 2015, respectively.

The following table summarizes our estimated aggregate amortization expense for the next five years and thereafter (in millions):

2018	$ 123.4
2019	123.4
2020	123.4
2021	123.4
2022	123.4
Thereafter	880.1
Total	$ 1,497.1

(5) Related Party Transactions

We engage in various transactions with Devon and other related parties. For the years ended December 31, 2017, 2016 and 2015, Devon was a significant customer to us. Devon accounted for 14.4%, 18.5% and 16.6% of our revenues for the years ended December 31, 2017, 2016 and 2015, respectively. We had an accounts receivable balance related to transactions with Devon of $102.7 million and $100.2 million as of December 31, 2017 and 2016, respectively. Additionally, we had an accounts payable balance related to transactions with Devon of $16.3 million and $10.4 million as of December 31, 2017 and 2016, respectively. Management believes these transactions are executed on terms that are fair and reasonable. The amounts from related party transactions are specified in the accompanying financial statements.

ENLINK MIDSTREAM PARTNERS, LP
Notes to Consolidated Financial Statements (Continued)

Gathering, Processing and Transportation Agreements Associated with Our Business Combination with Devon

As described in "Note 1—Organization and Summary of Significant Agreements," Midstream Holdings was previously a wholly-owned subsidiary of Devon, and all of its assets were contributed to it by Devon. On January 1, 2014, in connection with the consummation of the Business Combination, EnLink Midstream Services, LLC, a wholly-owned subsidiary of Midstream Holdings ("EnLink Midstream Services"), entered into 10-year gathering and processing agreements with Devon pursuant to which EnLink Midstream Services provides gathering, treating, compression, dehydration, stabilization, processing and fractionation services, as applicable, for natural gas delivered by Devon Gas Services, L.P., a subsidiary of Devon ("Gas Services"), to Midstream Holdings' gathering and processing systems in the Barnett, Cana-Woodford and Arkoma-Woodford Shales. On January 1, 2014, SWG Pipeline, L.L.C. ("SWG Pipeline"), another wholly-owned subsidiary of Midstream Holdings, entered into a 10-year gathering agreement with Devon pursuant to which SWG Pipeline provides gathering, treating, compression, dehydration and redelivery services, as applicable, for natural gas delivered by Gas Services to another of our gathering systems in the Barnett Shale.

These agreements provide Midstream Holdings with dedication of all of the natural gas owned or controlled by Devon and produced from or attributable to existing and future wells located on certain oil, natural gas and mineral leases covering land within the acreage dedications, excluding properties previously dedicated to other natural gas gathering systems not owned and operated by Devon. Pursuant to the gathering and processing agreements entered into on January 1, 2014, Devon has committed to deliver specified minimum daily volumes of natural gas to Midstream Holdings' gathering systems in the Barnett, Cana-Woodford and Arkoma-Woodford Shales during each calendar quarter. We recognized revenue under these agreements of $615.5 million, $611.8 million and $596.3 million for the years ended December 31, 2017, 2016 and 2015, respectively. Included in these amounts of revenue recognized is revenue from MVCs attributable to Devon of $81.9 million, $46.2 million, and $24.4 million for the years ended December 31, 2017, 2016 and 2015, respectively. Devon is entitled to firm service, meaning that if capacity on a system is curtailed or reduced, or capacity is otherwise insufficient, Midstream Holdings will take delivery of as much Devon natural gas as is permitted in accordance with applicable law.

The gathering and processing agreements are fee-based, and Midstream Holdings is paid a specified fee per MMBtu for natural gas gathered on Midstream Holdings' gathering systems and a specified fee per MMBtu for natural gas processed. The particular fees, all of which are subject to an automatic annual inflation escalator at the beginning of each year, differ from one system to another and do not contain a fee redetermination clause.

In connection with the closing of the Business Combination, Midstream Holdings entered into an agreement with a wholly-owned subsidiary of Devon pursuant to which Midstream Holdings provides transportation services to Devon on its Acacia pipeline.

EnLink Oklahoma T.O. Gathering and Processing Agreement with Devon

In January 2016, in connection with the acquisition of EnLink Oklahoma T.O., we acquired a gas gathering and processing agreement with Devon Energy Production Company, L.P. ("DEPC") pursuant to which EnLink Oklahoma T.O. provides gathering, treating, compression, dehydration, stabilization, processing and fractionation services, as applicable, for natural gas delivered by DEPC. The agreement has an MVC that will remain in place during each calendar quarter for four years and an overall term of approximately 15 years. Additionally, the agreement provides EnLink Oklahoma T.O. with dedication of all of the natural gas owned or controlled by DEPC and produced from or attributable to existing and future wells located on certain oil, natural gas and mineral leases covering land within the acreage dedications, excluding properties previously dedicated to other natural gas gathering systems not owned and operated by DEPC. DEPC is entitled to firm service, meaning a level of gathering and processing service in which DEPC's reserved capacity may not be interrupted, except due to force majeure, and may not be displaced by another customer or class of service. This agreement accounted for approximately $100.4 million and $34.4 million of our combined revenues for the years ended December 31, 2017 and 2016, respectively.

Cedar Cove Joint Venture

On November 9, 2016, we formed a joint venture (the "Cedar Cove JV") with Kinder Morgan, Inc. consisting of gathering and compression assets in Blaine County, Oklahoma. Under a 15-year, fixed-fee agreement, all gas gathered by the Cedar Cove JV will be processed at our Central Oklahoma processing system. For the period from November 9, 2016 through December 31, 2016, revenue generated from processing gas from the Cedar Cove JV was immaterial. For the year ended December 31, 2017, we recorded service revenue of $5.4 million that is recorded as "Midstream services—related parties" on the consolidated statements of operations. In addition, for the year ended December 31, 2017, we recorded cost of sales of $30.6 million related to our purchase of residue gas and NGLs from the Cedar Cove JV subsequent to processing at our Central Oklahoma processing facilities.

Other Commercial Relationships with Devon

As noted above, we continue to maintain a customer relationship with Devon originally established prior to the Business Combination pursuant to which we provide gathering, transportation, processing and gas lift services to Devon in exchange for fee-based compensation under several agreements with Devon. The terms of these agreements vary, but the agreements began to expire in January 2016 and continue to expire through July 2021, renewing automatically for month-to-month or year-to-year periods unless canceled by Devon prior to expiration. In addition, we have agreements with Devon pursuant to which we purchase and sell NGLs, gas and crude oil and pay or receive, as applicable, a margin-based fee. These NGL, gas and crude oil purchase and sale agreements have month-to-month terms. These historical agreements collectively comprise $78.0 million, $107.2 million and $107.5 million of our combined revenue for the years ended December 31, 2017, 2016, and 2015, respectively.

VEX Transportation Agreement

In connection with the VEX Drop Down, we became party to a five-year transportation services agreement with Devon pursuant to which we provide transportation services to Devon on the VEX pipeline. This agreement includes a five-year MVC with Devon. The MVC was executed in June 2014, and the initial term expires July 2019.This agreement accounted for approximately $17.8 million, $18.7 million and $17.8 million of service revenues for the years ended December 31, 2017, 2016 and 2015, respectively.

Acacia Transportation Agreement

In connection with the consummation of the Business Combination, we entered into an agreement with a wholly-owned subsidiary of Devon pursuant to which we provide transportation services to Devon on its Acacia line. This agreement accounted for approximately $13.8 million, $15.2 million and $16.4 million of our combined revenues for the years ended December 31, 2017, 2016 and 2015, respectively.

GCF Agreement

In connection with the consummation of the Business Combination, we entered into an agreement with a wholly-owned subsidiary of Devon pursuant to which Devon agreed, from and after the closing of the Business Combination, to hold for the benefit of Midstream Holdings the economic benefits and burdens of Devon's 38.75% general partner interest in Gulf Coast Fractionators in Mont Belvieu, Texas. This agreement contributed approximately $12.6 million, $3.4 million and $13.0 million to our income from unconsolidated affiliate investment for the years ended December 31, 2017, 2016 and 2015, respectively.

Transactions with ENLC

ENLC paid us $2.4 million, $2.3 million, and $2.1 million as reimbursement during the years ended December 31, 2017, 2016, and 2015, respectively, to cover its portion of administrative and compensation costs for officers and employees that perform services for ENLC. This reimbursement is evaluated on an annual basis. Officers and employees that perform services for ENLC provide an estimate of the portion of their time devoted to such services. A portion of their annual compensation (including bonuses, payroll taxes and other benefit costs) is allocated to ENLC for reimbursement based on these estimates. In addition, an administrative burden is added to such costs to reimburse us for additional support costs, including, but not limited to, consideration for rent, office support and information service support.

ENLC paid us $48.4 million and $31.5 million for their interest in EnLink Oklahoma T.O.s' capital expenditures for the years ended December 31, 2017 and 2016, respectively. ENLC pays its contribution for EnLink Oklahoma T.O.'s capital expenditures to us monthly, net of EnLink Oklahoma T.O.'s adjusted EBITDA distributable to ENLC, which is defined as earnings before depreciation and amortization and provision for income taxes and includes allocated expenses from us.

On October 29, 2015, we issued 2,849,100 common units at an offering price of $17.55 per common unit to a subsidiary of ENLC for aggregate consideration of approximately $50.0 million in a private placement transaction.

Tax Sharing Agreement

In connection with the consummation of the Business Combination, we, ENLC and Devon, entered into a tax sharing agreement providing for the allocation of responsibilities, liabilities and benefits relating to any tax for which a combined tax return is due. For the years ended December 31, 2017, 2016 and 2015 we incurred approximately $1.2 million, $2.3 million and $3.0 million, respectively, in taxes that are subject to the tax sharing agreement.

(6) Long-Term Debt

As of December 31, 2017 and 2016, long-term debt consisted of the following (in millions):

	December 31, 2017			December 31, 2016		
	Outstanding Principal	Premium (Discount)	Long-Term Debt	Outstanding Principal	Premium (Discount)	Long-Term Debt
Partnership credit facility, due 2020 (1)	$ —	$ —	$ —	$ 120.0	$ —	$ 120.0
2.70% Senior unsecured notes due 2019	400.0	(0.1)	399.9	400.0	(0.3)	399.7
7.125% Senior unsecured notes due 2022	—	—	—	162.5	16.0	178.5
4.40% Senior unsecured notes due 2024	550.0	2.2	552.2	550.0	2.5	552.5
4.15% Senior unsecured notes due 2025	750.0	(1.0)	749.0	750.0	(1.1)	748.9
4.85% Senior unsecured notes due 2026	500.0	(0.6)	499.4	500.0	(0.7)	499.3
5.60% Senior unsecured notes due 2044	350.0	(0.2)	349.8	350.0	(0.2)	349.8
5.05% Senior unsecured notes due 2045	450.0	(6.5)	443.5	450.0	(6.6)	443.4
5.45% Senior unsecured notes due 2047	500.0	(0.1)	499.9	—	—	—
Debt classified as long-term	$ 3,500.0	$ (6.3)	3,493.7	$ 3,282.5	$ 9.6	3,292.1
Debt issuance cost (2)			(25.9)			(24.1)
Long-term debt, net of unamortized issuance cost			$ 3,467.8			$ 3,268.0

(1) Bears interest based on Prime and/or LIBOR plus an applicable margin. The effective interest rate was 2.3% at December 31, 2016.
(2) Net of amortization of $12.0 million and $8.3 million at December 31, 2017 and 2016, respectively.

Maturities

Maturities for the long-term debt as of December 31, 2017 are as follows (in millions):

2018	$ —
2019	400.0
2020	—
2021	—
2022	—
Thereafter	3,100.0
Subtotal	3,500.0
Less: net discount	(6.3)
Less: debt issuance cost	(25.9)
Long-term debt, net of unamortized issuance cost	$ 3,467.8

Credit Facility

We have a $1.5 billion unsecured revolving credit facility that matures on March 6, 2020, and includes a $500.0 million letter of credit subfacility. Under our credit facility, we are permitted to (1) subject to certain conditions and the receipt of additional commitments by one or more lenders, increase the aggregate commitments under our credit facility by an additional amount not to exceed $500.0 million, and (2) subject to certain conditions and the consent of the requisite lenders, on two separate occasions, extend the maturity date of our credit facility by one year on each occasion. Our credit facility contains certain financial, operational and legal covenants. Among other things, these covenants include maintaining a ratio of consolidated indebtedness to consolidated EBITDA (which is defined in our credit facility and includes projected EBITDA from certain capital expansion projects) of no more than 5.0 to 1.0. If we consummate one or more acquisitions in which the aggregate purchase price is $50.0 million or more, we can elect to increase the maximum allowed ratio of consolidated indebtedness to consolidated EBITDA to 5.5 to 1.0 for the quarter of the acquisition and the three following quarters.

Borrowings under our credit facility bear interest at our option at the Eurodollar Rate (the LIBOR Rate) plus an applicable margin (ranging from 1.00% to 1.75%) or the Base Rate (the highest of the Federal Funds Rate plus 0.50%, the 30-day Eurodollar Rate plus 1.0% or the administrative agent's prime rate) plus an applicable margin (ranging from 0.0% to 0.75%). The applicable margins vary depending on our credit rating. If we breach certain covenants governing our credit facility, amounts outstanding under our credit facility, if any, may become due and payable immediately. At December 31, 2017, we were in compliance and expect to be in compliance with the covenants in our credit facility for at least the next twelve months.

As of December 31, 2017, there were $9.8 million in outstanding letters of credit and no outstanding borrowings under our credit facility, leaving approximately $1.5 billion available for future borrowing.

Issuances and Redemptions of Senior Unsecured Notes

On March 7, 2014, we recorded $196.5 million in aggregate principal amount of 7.125% senior unsecured notes (the "2022 Notes") due on June 1, 2022 in the Business Combination. The interest payments on the 2022 Notes were due semi-annually in arrears in June and December. As a result of the Business Combination, the 2022 Notes were recorded at fair value in accordance with acquisition accounting at an amount of $226.0 million, including a premium of $29.5 million. On July 20, 2014, we redeemed $18.5 million aggregate principal amount of the 2022 Notes for $20.0 million, including accrued interest. On September 20, 2014, we redeemed an additional $15.5 million aggregate principal amount of the 2022 Notes for $17.0 million, including accrued interest. On June 1, 2017, we redeemed the remaining $162.5 million in aggregate principal amount of the 2022 Notes at 103.6% of the principal amount, plus accrued unpaid interest, for aggregate cash consideration of $174.1 million, which resulted in a gain on extinguishment of debt of $9.0 million for the year ended December 31, 2017.

On March 19, 2014, we issued $1.2 billion aggregate principal amount of unsecured senior notes, consisting of $400.0 million aggregate principal amount of our 2.700% senior notes due 2019 (the "2019 Notes"), $450.0 million aggregate principal amount of our 4.400% senior notes due 2024 (the "2024 Notes") and $350.0 million aggregate principal amount of our 5.600% senior notes due 2044 (the "2044 Notes"), at prices to the public of 99.850%, 99.830% and 99.925%, respectively, of their face value. The 2019 Notes mature on April 1, 2019; the 2024 Notes mature on April 1, 2024; and the 2044 Notes mature on April 1, 2044. The interest payments on the 2019 Notes, 2024 Notes and 2044 Notes are due semi-annually in arrears in April and October.

On November 12, 2014, we issued an additional $100.0 million aggregate principal amount of the 2024 Notes and $300.0 million aggregate principal amount of our 5.050% senior notes due 2045 (the "2045 Notes"), at prices to the public of 104.007% and 99.452%, respectively, of their face value. The new 2024 Notes were offered as an additional issue of our outstanding 2024 Notes issued on March 19, 2014. The 2024 Notes issued on March 19, 2014 and November 12, 2014 are treated as a single class of debt securities and have identical terms, other than the issue date. The 2045 Notes mature on April 1, 2045, and interest payments on the 2045 Notes are due semi-annually in arrears in April and October.

On May 12, 2015, we issued $900.0 million aggregate principal amount of unsecured senior notes, consisting of $750.0 million aggregate principal amount of our 4.150% senior notes due 2025 (the "2025 Notes") and an additional $150.0 million aggregate principal amount of 2045 Notes at prices to the public of 99.827% and 96.381%, respectively, of their face value. The 2025 Notes mature on June 1, 2025. Interest payments on the 2025 Notes are due semi-annually in arrears in June and December. The new 2045 Notes were offered as an additional issue of our outstanding 2045 Notes issued on November 12,

2014. The 2045 Notes issued on November 12, 2014 and May 12, 2015 are treated as a single class of debt securities and have identical terms, other than the issue date.

On July 14, 2016, we issued $500.0 million in aggregate principal amount of our 4.850% senior notes due 2026 (the “2026 Notes”) at a price to the public of 99.859% of their face value. The 2026 Notes mature on July 15, 2026. Interest payments on the 2026 Notes are payable on January 15 and July 15 of each year. Net proceeds of approximately $495.7 million were used to repay outstanding borrowings under our credit facility and for general partnership purposes.

On May 11, 2017, we issued $500.0 million in aggregate principal amount of our 5.450% senior unsecured notes due June 1, 2047 (the “2047 Notes”) at a price to the public of 99.981% of their face value. Interest payments on the 2047 Notes are payable on June 1 and December 1 of each year, beginning December 1, 2017. Net proceeds of approximately $495.2 million were used to repay outstanding borrowings under our credit facility and for general partnership purposes.

Senior Unsecured Note Redemption Provisions

Each issuance of the senior unsecured notes may be fully or partially redeemed prior to an early redemption date (see "Early Redemption Date" in table below) at a redemption price equal to the greater of: (i) 100% of the principal amount of the notes to be redeemed; or (ii) the sum of the remaining scheduled payments of principal and interest on the respective notes to be redeemed that would be due after the related redemption date but for such redemption (exclusive of interest accrued to, but excluding the redemption date) discounted to the redemption date on a semi-annual basis (assuming a 360-day year consisting of twelve 30-day months) at the applicable Treasury Rate plus a specified basis point premium (see "Basis Point Premium" in the table below); plus accrued and unpaid interest to, but excluding, the redemption date. At any time on or after the Early Redemption Date, the senior unsecured notes may be fully or partially redeemed at a redemption price equal to 100% of the principal amount of the applicable notes to be redeemed plus accrued and unpaid interest to, but excluding, the redemption date. See applicable redemption provision terms below:

Issuance	Maturity Date of Notes	Early Redemption Date	Basis Point Premium
2019 Notes	April 1, 2019	Prior to March 1, 2019	20 Basis Points
2024 Notes	April 1, 2024	Prior to January 1, 2024	25 Basis Points
2025 Notes	June 1, 2025	Prior to March 1, 2025	30 Basis Points
2026 Notes	July 15, 2026	Prior to April 15, 2026	50 Basis Points
2044 Notes	April 1, 2044	Prior to October 1, 2043	30 Basis Points
2045 Notes	April 1, 2045	Prior to October 1, 2044	30 Basis Points
2047 Notes	June 1, 2047	Prior to June 1, 2047	40 Basis Points

Senior Unsecured Note Indentures

The indentures governing the senior unsecured notes contain covenants that, among other things, limit our ability to create or incur certain liens or consolidate, merge or transfer all or substantially all of our assets.

Each of the following is an event of default under the indentures:

- failure to pay any principal or interest when due;
- failure to observe any other agreement, obligation or other covenant in the indenture, subject to the cure periods for certain failures; and
- bankruptcy or other insolvency events involving us.

If an event of default relating to bankruptcy or other insolvency events occurs, the senior unsecured notes will immediately become due and payable. If any other event of default exists under the indenture, the trustee under the indenture or the holders of the senior unsecured notes may accelerate the maturity of the senior unsecured notes and exercise other rights and remedies. At December 31, 2017, we were in compliance and expect to be in compliance with the covenants in the senior unsecured notes for at least the next twelve months.

(7) Income Taxes

The components of our income tax provision (benefit) are as follows (in millions):

	Year Ended December 31,		
	2017	2016	2015
Current income tax provision	$ 2.6	$ 1.9	$ 3.1
Deferred tax benefit	(26.6)	(0.6)	(3.6)
Total income tax provision (benefit)	$ (24.0)	$ 1.3	$ (0.5)

Net income for financial statement purposes may differ significantly from taxable income of unitholders because of differences between the tax basis and financial reporting basis of assets and liabilities and the taxable income allocation requirements under our partnership agreement. The aggregate difference in the basis of our net assets for financial and tax reporting purposes cannot be readily determined because information regarding each partner's tax attributes is not available to us.

On December 22, 2017, the Tax Cuts and Jobs Act was signed into legislation and resulted in a change in the federal statutory corporate tax rate from 35% to 21%, effective January 1, 2018. Accordingly, we have reduced deferred tax liabilities and recorded a deferred tax benefit in the amount of $24.9 million due to a remeasurement of deferred tax liabilities primarily related to our wholly-owned corporate entities.

Deferred tax liabilities of $46.3 million and $73.0 million existed at December 31, 2017 and 2016, respectively. Deferred tax liabilities as of December 31, 2017 and 2016 included $38.8 million and $63.1 million related to our wholly-owned corporate entity that was formed to acquire the common stock of Clearfield Energy, Inc. This deferred tax liability represents the future tax payable on the difference between the fair value and the carryover tax basis of the assets acquired and is expected to become payable no later than 2027.

As of December 31, 2017 and 2016, there was no recorded unrecognized tax benefit. A reconciliation of the beginning and ending amount of unrecognized tax benefits is as follows (in millions):

	Year Ended December 31,		
	2017	2016	2015
Beginning Balance, January 1	$ —	$ 1.5	$ 2.0
Decrease due to prior year tax positions	—	(1.5)	(0.5)
Ending Balance, December 31	$ —	$ —	$ 1.5

Per our accounting policy election, penalties and interest related to unrecognized tax benefits are recorded to income tax expense. As of December 31, 2017, tax years 2013 through 2017 remain subject to examination by various taxing authorities.

(8) Partners' Capital

(a) Issuance of Common Units

In November 2014, we entered into an Equity Distribution Agreement (the "2014 EDA") with BMO Capital Markets Corp., Merrill Lynch, Pierce, Fenner & Smith Incorporated, Citigroup Global Markets Inc., Jefferies LLC, Raymond James & Associates, Inc. and RBC Capital Markets, LLC to sell up to $350.0 million in aggregate gross sales of our common units from time to time through an "at the market" equity offering program.

For the year ended December 31, 2015, we sold an aggregate of 1.3 million common units under the 2014 EDA, generating proceeds of approximately $24.4 million (net of approximately $0.3 million of commissions). For the year ended December 31, 2016, we sold an aggregate of 10.0 million common units under the 2014 EDA, generating proceeds of approximately $167.5 million (net of approximately $1.7 million of commissions).

In August 2017, we ceased trading under the 2014 EDA and entered into an Equity Distribution Agreement (the "2017 EDA") with UBS Securities LLC, Barclays Capital Inc., BMO Capital Markets Corp., Merrill Lynch, Pierce, Fenner & Smith

Incorporated, Citigroup Markets Inc., Jefferies LLC, Mizuho Securities USA LLC, RBC Capital Markets, LLC, SunTrust Robinson Humphrey, Inc. and Wells Fargo Securities, LLC (collectively, the "Sales Agents") to sell up to $600.0 million in aggregate gross sales of our common units from time to time through an "at the market" equity offering program. We may also sell common units to any Sales Agent as principal for the Sales Agent's own account at a price agreed upon at the time of sale. We have no obligation to sell any of the common units under the 2017 EDA and may at any time suspend solicitation and offers under the 2017 EDA.

For the year ended December 31, 2017, we sold an aggregate of approximately 6.2 million common units under the 2014 EDA and the 2017 EDA, generating proceeds of approximately $106.9 million (net of approximately $1.1 million of commissions and $0.2 million of registration fees). We used the net proceeds for general partnership purposes. As of December 31, 2017, approximately $565.4 million remains available to be issued under the 2017 EDA.

On October 29, 2015, we issued 2,849,100 common units at an offering price of $17.55 per unit to a subsidiary of ENLC for aggregate consideration of approximately $50.0 million in a private placement transaction.

As explained in "Note 1—Organization and Summary of Significant Agreements," in 2015, Acacia contributed its remaining 50% interest in Midstream Holdings to us in exchange for 68.2 million units of our limited partnership interests in the EMH Drop Downs.

(b) Class C Common Units

In March 2015, we issued 6,704,285 Class C Common Units representing a new class of limited partner interests as partial consideration for the acquisition of Coronado. The Class C Common Units were substantially similar in all respects to our common units, except that distributions paid on the Class C Common Units could be paid in cash or in additional Class C Common Units issued in kind, as determined by our general partner in its sole discretion. Distributions on the Class C Common Units for the three months ended March 31, 2015, June 30, 2015, and September 30, 2015 were paid-in-kind through the issuance of 99,794, 120,622, and 150,732 Class C Common Units on May 14, 2015, August 13, 2015, and November 12, 2015, respectively. Distributions on the Class C Common Units for the three months ended December 31, 2015 and March 31, 2016 were paid-in-kind through the issuance of 209,044 and 233,107 Class C Common Units on February 11, 2016 and May 12, 2016, respectively. All of the outstanding Class C Common Units were converted into common units on a one-for-one basis on May 13, 2016.

(c) Series B Preferred Units

In January 2016, we issued an aggregate of 50,000,000 Series B Preferred Units representing our limited partner interests to Enfield Holdings, L.P. ("Enfield") in a private placement for a cash purchase price of $15.00 per Series B Preferred Unit (the "Issue Price"), resulting in net proceeds of approximately $724.1 million after fees and deductions. Proceeds from the private placement were used to partially fund our portion of the purchase price payable in connection with the acquisition of our EnLink Oklahoma T.O. assets. Affiliates of the Goldman Sachs Group, Inc. and affiliates of TPG Global, LLC own interests in the general partner of Enfield. The Series B Preferred Units are convertible into our common units on a one-for-one basis, subject to certain adjustments, (a) in full, at our option, if the volume weighted average price of a common unit over the 30-trading day period ending two trading days prior to the conversion date (the "Conversion VWAP") is greater than 150% of the Issue Price or (b) in full or in part, at Enfield's option. In addition, upon certain events involving a change of control of our general partner or the managing member of ENLC, all of the Series B Preferred Units will automatically convert into a number of common units equal to the greater of (i) the number of common units into which the Series B Preferred Units would then convert and (ii) the number of Series B Preferred Units to be converted multiplied by an amount equal to (x) 140% of the Issue Price divided by (y) the Conversion VWAP.

For each of the calendar quarters between March 31, 2016 through June 30, 2017, Enfield received a quarterly distribution equal to an annual rate of 8.5% on the Issue Price payable in-kind in the form of additional Series B Preferred Units. For the quarter ended September 30, 2017 and each subsequent quarter, Enfield received or is entitled to receive a quarterly distribution, subject to certain adjustments, equal to an annual rate of 7.5% on the Issue Price payable in cash (the "Cash Distribution Component") plus an in-kind distribution equal to the greater of (A) 0.0025 Series B Preferred Units per Series B Preferred Unit and (B) an amount equal to (i) the excess, if any, of the distribution that would have been payable had the Series B Preferred Units converted into common units over the Cash Distribution Component, divided by (ii) the Issue Price. Income is allocated to the Series B Preferred Units in an amount equal to the quarterly distribution with respect to the period earned.

For the years ended December 31, 2017 and 2016, $86.0 million and $69.9 million of income was allocated to the Series B Preferred Units, respectively.

A summary of the distribution activity relating to the Series B Preferred Units for the years ended December 31, 2017 and 2016 is provided below:

Declaration period	Distribution paid as additional Series B Preferred Units	Cash distribution (in millions)		Date paid/payable
2017				
First Quarter of 2017	1,154,147	$	—	May 12, 2017
Second Quarter of 2017	1,178,672	$	—	August 11, 2017
Third Quarter of 2017	410,681	$	15.9	November 13, 2017
Fourth Quarter of 2017	413,658	$	16.1	February 13, 2018
2016				
First Quarter of 2016	992,445	$	—	May 12, 2016
Second Quarter of 2016	1,083,589	$	—	August 11, 2016
Third Quarter of 2016	1,106,616	$	—	November 10, 2016
Fourth Quarter of 2016	1,130,131	$	—	February 13, 2017

(d) Series C Preferred Units

In September 2017, we issued 400,000 Series C Fixed-to-Floating Rate Cumulative Redeemable Perpetual Preferred Units (the "Series C Preferred Units") representing our limited partner interests at a price to the public of $1,000 per unit. We used the net proceeds of $394.0 million for capital expenditures, general partnership purposes and to repay borrowings under our credit facility. The Series C Preferred Units represent perpetual equity interests in us and, unlike our indebtedness, will not give rise to a claim for payment of a principal amount at a particular date. As to the payment of distributions and amounts payable on a liquidation event, the Series C Preferred Units rank senior to our common units and to each other class of limited partner interests or other equity securities established after the issue date of the Series C Preferred Units that is not expressly made senior or on parity with the Series C Preferred Units. The Series C Preferred Units rank junior to the Series B Preferred Units with respect to the payment of distributions, and junior to the Series B Preferred Units and all current and future indebtedness with respect to amounts payable upon a liquidation event. Income is allocated to the Series C Preferred Units in an amount equal to the earned distributions for the respective reporting period. For the year ended December 31, 2017, $6.7 million of income was allocated to the Series C Preferred Units.

At any time on or after December 15, 2022, we may redeem, at our option, in whole or in part, the Series C Preferred Units at a redemption price in cash equal to $1,000 per Series C Preferred Unit plus an amount equal to all accumulated and unpaid distributions, whether or not declared. We may undertake multiple partial redemptions. In addition, at any time within 120 days after the conclusion of any review or appeal process instituted by us following certain rating agency events, we may redeem, at our option, the Series C Preferred Units in whole at a redemption price in cash per unit equal to $1,020 plus an amount equal to all accumulated and unpaid distributions, whether or not declared.

Distributions on the Series C Preferred Units accrue and are cumulative from the date of original issue and payable semi-annually in arrears on the 15th day of June and December of each year through and including December 15, 2022 and, thereafter, quarterly in arrears on the 15th day of March, June, September and December of each year, in each case, if and when declared by our general partner out of legally available funds for such purpose. The initial distribution rate for the Series C Preferred Units from and including the date of original issue to, but not including, December 15, 2022 is 6.0% per annum. On and after December 15, 2022, distributions on the Series C Preferred Units will accumulate for each distribution period at a percentage of the $1,000 liquidation preference per unit equal to an annual floating rate of the three-month LIBOR plus a spread of 4.11%. For the year ended December 31, 2017, we made distributions of $5.6 million to holders of Series C Preferred Units.

(e) Common Unit Distributions

Unless restricted by the terms of our credit facility and/or the indentures governing our senior unsecured notes, we must make distributions of 100% of available cash, as defined in the partnership agreement, within 45 days following the end of each quarter. Distributions are made to the general partner in accordance with its current percentage interest with the remainder to the common unitholders, subject to the payment of incentive distributions as described below to the extent that certain target levels of cash distributions are achieved. The general partner was not entitled to its incentive distributions with respect to the Class C Common Units issued in kind. In addition, the general partner is not entitled to its incentive distributions with respect to (i) distributions on the Series B Preferred Units until such units convert into common units or (ii) the Series C Preferred Units.

Our general partner owns the general partner interest in us and all of our incentive distribution rights. Our general partner is entitled to receive incentive distributions if the amount we distribute with respect to any quarter exceeds levels specified in our partnership agreement. Under the quarterly incentive distribution provisions, our general partner is entitled to 13.0% of amounts we distribute in excess of $0.25 per unit, 23.0% of the amounts we distribute in excess of $0.3125 per unit and 48.0% of amounts we distribute in excess of $0.375 per unit.

A summary of the distribution activity relating to the common units for the years ended December 31, 2017, 2016 and 2015 is provided below:

Declaration period	Distribution/unit		Date paid/payable
2017			
First Quarter of 2017	$	0.390	May 12, 2017
Second Quarter of 2017	$	0.390	August 11, 2017
Third Quarter of 2017	$	0.390	November 13, 2017
Fourth Quarter of 2017	$	0.390	February 13, 2018
2016			
First Quarter of 2016	$	0.390	May 12, 2016
Second Quarter of 2016	$	0.390	August 11, 2016
Third Quarter of 2016	$	0.390	November 11, 2016
Fourth Quarter of 2016	$	0.390	February 13, 2017
2015			
First Quarter of 2015	$	0.380	May 14, 2015
Second Quarter of 2015	$	0.385	August 13, 2015
Third Quarter of 2015	$	0.390	November 12, 2015
Fourth Quarter of 2015	$	0.390	February 11, 2016

(f) Earnings Per Unit and Dilution Computations

As required under ASC 260, *Earnings Per Share*, unvested share-based payments that entitle employees to receive non-forfeitable distributions are considered participating securities for earnings per unit calculations. The following table reflects the computation of basic and diluted earnings per limited partner units for the periods presented (in millions, except per unit amounts):

	Year Ended December 31,		
	2017	2016	2015
Limited partners' interest in net income (loss)	$ 17.9	$ (662.1)	$ (1,405.2)
Distributed earnings allocated to:			
Common units (1)	$ 541.2	$ 520.0	$ 465.9
Unvested restricted units (1)	4.0	3.5	2.0
Total distributed earnings	$ 545.2	$ 523.5	$ 467.9
Undistributed loss allocated to:			
Common units	$ (523.5)	$ (1,177.6)	$ (1,865.3)
Unvested restricted units	(3.8)	(8.0)	(7.8)
Total undistributed loss	$ (527.3)	$ (1,185.6)	$ (1,873.1)
Net income (loss) allocated to:			
Common units	$ 17.7	$ (657.6)	$ (1,399.4)
Unvested restricted units	0.2	(4.5)	(5.8)
Total limited partners' interest in net income (loss)	$ 17.9	$ (662.1)	$ (1,405.2)
Basic and diluted net income (loss) per unit:			
Basic	$ 0.05	$ (1.99)	$ (4.66)
Diluted	$ 0.05	$ (1.99)	$ (4.66)

(1) Represents distribution activity consistent with the distribution activity table in section "(e) Common Unit Distributions" above.

The following are the unit amounts used to compute the basic and diluted earnings per limited partner unit for the years ended December 31, 2017, 2016 and 2015 (in millions):

	Year Ended December 31,		
	2017	2016	2015
Basic weighted average units outstanding:			
Weighted average limited partner basic common units outstanding (1)	346.9	333.3	307.1
Diluted weighted average units outstanding:			
Weighted average limited partner basic common units outstanding (1)	346.9	333.3	307.1
Dilutive effect of non-vested restricted units (2)	1.4	—	—
Total weighted average limited partner diluted common units outstanding	348.3	333.3	307.1

(1) Weighted average limited partner basic common units outstanding for the years ended December 31, 2016 and 2015 included the weighted average impact of 2,740,273 and 5,459,905 Class C Units, respectively, which converted into common units on May 13, 2016.
(2) All common unit equivalents were antidilutive for the years ended December 31, 2016 and 2015 because the limited partners were allocated a net loss.

All outstanding units were included in the computation of diluted earnings per unit and weighted based on the number of days such units were outstanding during the period presented.

Net income is allocated to our general partner in an amount equal to its incentive distribution rights as described in section "(e) Common Unit Distributions" above. Our general partner's share of net income consists of incentive distribution rights to the extent earned, a deduction for unit-based compensation attributable to ENLC's restricted units and the percentage interest of our net income adjusted for ENLC's unit-based compensation specifically allocated to our general partner and net income attributable to the drop down transactions described in "Note 1—Organization and Summary of Significant Agreements." The net income allocated to the general partner is as follows (in millions):

	Year Ended December 31,		
	2017	2016	2015
Income allocation for incentive distributions	$ 58.9	$ 56.8	$ 47.5
Unit-based compensation attributable to ENLC's restricted units	(21.0)	(14.7)	(18.3)
General partner share of net income (loss)	0.4	(2.6)	(6.7)
General partner interest in drop down transactions	—	—	35.5
General partner interest in net income	$ 38.3	$ 39.5	$ 58.0

(9) Asset Retirement Obligations

The schedule below summarizes the changes in our asset retirement obligations (in millions):

	Year Ended December 31,	
	2017	2016
Balance, beginning of period	$ 13.5	$ 14.0
Revisions to the fair values of existing liabilities	—	(0.5)
Accretion expense	0.7	0.6
Liabilities settled	—	(0.6)
Balance, end of period	$ 14.2	$ 13.5

Asset retirement obligations of $14.2 million and $13.5 million were included in "Asset retirement obligations" as non-current liabilities on the consolidated balance sheets as of December 31, 2017 and 2016, respectively.

(10) Investment in Unconsolidated Affiliates

Our unconsolidated investments consisted of:

- a contractual right to the economic benefits and burdens associated with Devon's 38.75% ownership interest in GCF at December 31, 2017, 2016 and 2015;

- an approximate 30.0% ownership in the Cedar Cove JV at December 31, 2017 and 2016. On November 9, 2016, we formed the Cedar Cove JV with Kinder Morgan, Inc., which consists of gathering and compression assets in Blaine County, Oklahoma, the heart of the Sooner Trend Anadarko Basin Canadian and Kingfisher Counties play; and

- an approximate 31% ownership interest in Howard Energy Partners ("HEP") at December 31, 2016 and 2015, which was sold in March 2017 for aggregate net proceeds of $189.7 million.

The following table shows the activity related to our investment in unconsolidated affiliates for the periods indicated (in millions):

	Year Ended December 31,		
	2017	2016	2015
Gulf Coast Fractionators			
Contributions	$ —	$ —	$ —
Distributions	$ 12.7	$ 7.5	$ 14.5
Equity in income	$ 12.6	$ 3.4	$ 13.0
Howard Energy Partners			
Contributions (1)	$ —	$ 45.0	$ 25.8
Distributions (2)	$ —	$ 50.2	$ 28.2
Equity in income (loss) (3)	$ (3.4)	$ (23.3)	$ 7.4
Cedar Cove JV			
Contributions	$ 12.6	$ 28.8	$ —
Distributions	$ 0.8	$ —	$ —
Equity in income	$ 0.4	$ —	$ —
Total			
Contributions (1)	$ 12.6	$ 73.8	$ 25.8
Distributions (2)	$ 13.5	$ 57.7	$ 42.7
Equity in income (loss) (3)	$ 9.6	$ (19.9)	$ 20.4

(1) Contributions for the year ended December 31, 2016 included $32.7 million of contributions to HEP for preferred units issued by HEP. These preferred units were redeemed during the third quarter 2016.
(2) Distributions for the year ended December 31, 2016 included a redemption of $32.7 million of preferred units issued by HEP.
(3) Included losses of $3.4 million and $20.1 million for the years ended December 31, 2017 and 2016, respectively, related to the sale of our HEP interests.

The following table shows the balances related to our investment in unconsolidated affiliates as ofDecember 31, 2017 and 2016 (in millions):

	December 31, 2017	December 31, 2016
Gulf Coast Fractionators	$ 48.4	$ 48.5
Howard Energy Partners (1)	—	193.1
Cedar Cove JV	41.0	28.8
Total investments in unconsolidated affiliates	$ 89.4	$ 270.4

(1) Due to the completion of the sale of our investment in HEP in the first quarter of 2017, the HEP investment balance was classified as “Investment in unconsolidated affiliates—current” on the consolidated balance sheet as of December 31, 2016.

(11) Employee Incentive Plans

(a) Long-Term Incentive Plans

ENLK and ENLC each have similar unit-based compensation payment plans for officers and employees. We grant unit-based awards under the amended and restated EnLink Midstream GP, LLC Long-Term Incentive Plan (the “GP Plan”), and ENLC grants unit-based awards under the EnLink Midstream, LLC 2014 Long-Term Incentive Plan (the “2014 Plan”).

We account for unit-based compensation in accordance with ASC 718, which requires that compensation related to all unit-based awards be recognized in the consolidated financial statements. Unit-based compensation cost is valued at fair value at the date of grant, and that grant date fair value is recognized as expense over each award's requisite service period with a corresponding increase to equity or liability based on the terms of each award and the appropriate accounting treatment under ASC 718. Unit-based compensation associated with ENLC's unit-based compensation plan awarded to our officers and employees is recorded by us, since ENLC has no substantial or managed operating activities other than its interest in ENLK and EnLink Oklahoma T.O.

Amounts recognized on the consolidated financial statements with respect to these plans are as follows (in millions):

	Year Ended December 31,		
	2017	2016	2015
Cost of unit-based compensation charged to general and administrative expense	$ 37.1	$ 23.4	$ 30.7
Cost of unit-based compensation charged to operating expense	10.7	6.6	5.0
Total unit-based compensation expense	$ 47.8	$ 30.0	$ 35.7

(b) EnLink Midstream Partners, LP's Restricted Incentive Units

ENLK restricted incentive units are valued at their fair value at the date of grant, which is equal to the market value of the ENLK common units on such date. A summary of the restricted incentive unit activity for the year ended December 31, 2017 is provided below:

	Year Ended December 31, 2017	
EnLink Midstream Partners, LP Restricted Incentive Units:	**Number of Units**	**Weighted Average Grant-Date Fair Value**
Non-vested, beginning of period	2,024,820	$ 19.05
Granted (1)	870,088	18.38
Vested (1)(2)	(873,229)	25.85
Forfeited	(41,455)	16.53
Non-vested, end of period	1,980,224	$ 15.81
Aggregate intrinsic value, end of period (in millions)	$ 30.4	

(1) Restricted incentive units typically vest at the end of three years. In March 2017, our general partner granted 262,288 restricted incentive units with a fair value of $5.1 million to officers and certain employees as bonus payments for 2016, and these restricted incentive units vested immediately and are included in the restricted incentive units granted and vested line items.
(2) Vested units include 279,827 units withheld for payroll taxes paid on behalf of employees.

A summary of the restricted incentive units' aggregate intrinsic value (market value at vesting date) and fair value of units vested (market value at date of grant) during the years ended December 31, 2017, 2016 and 2015 is provided below (in millions):

	Year Ended December 31,		
EnLink Midstream Partners, LP Restricted Incentive Units:	**2017**	**2016**	**2015**
Aggregate intrinsic value of units vested	$ 16.6	$ 4.1	$ 7.5
Fair value of units vested	$ 22.6	$ 9.5	$ 8.1

As of December 31, 2017, there was $11.6 million of unrecognized compensation cost related to non-vested ENLK restricted incentive units. That cost is expected to be recognized over a weighted-average period of 1.7 years.

(c) EnLink Midstream Partners, LP's Performance Units

In 2017, 2016 and 2015, our general partner granted performance awards under the GP Plan. The performance award agreements provide that the vesting of restricted incentive units granted thereunder is dependent on the achievement of certain total shareholder return ("TSR") performance goals relative to the TSR achievement of a peer group of companies (the "Peer Companies") over the applicable performance period. The performance award agreements contemplate that the Peer Companies for an individual performance award (the "Subject Award") are the companies comprising the Alerian MLP Index for Master Limited Partnerships ("AMZ"), excluding ENLK and ENLC, on the grant date for the Subject Award. The performance units will vest based on the percentile ranking of the average of ENLK's and ENLC's TSR achievement ("EnLink TSR") for the applicable performance period relative to the TSR achievement of the Peer Companies.

At the end of the vesting period, recipients receive distribution equivalents, if any, with respect to the number of performance units vested. The vesting of such units ranges from zero to 200% of the units granted depending on the EnLink TSR as compared to the TSR of the Peer Companies on the vesting date. The fair value of each performance unit is estimated as of the date of grant using a Monte Carlo simulation with the following assumptions used for all performance unit grants made under the plan: (i) a risk-free interest rate based on United States Treasury rates as of the grant date; (ii) a volatility assumption based on the historical realized price volatility of our common units and the designated Peer Companies securities; (iii) an estimated ranking of us among the Peer Companies; and (iv) the distribution yield. The fair value of the performance unit on the date of grant is expensed over a vesting period of approximately three years.

The following table presents a summary of the grant-date fair values of performance units granted and the related assumptions by performance unit grant date:

EnLink Midstream Partners, LP Performance Units:	March 2017	October 2016	February 2016	January 2016	March 2015
Beginning TSR price	$17.55	$17.71	$14.82	$14.82	$27.68
Risk-free interest rate	1.62%	0.91%	0.89%	1.10%	0.99%
Volatility factor	43.94%	44.62%	42.33%	39.71%	33.01%
Distribution yield	8.70%	8.80%	19.20%	12.10%	5.66%

The following table presents a summary of the performance units:

	Year Ended December 31, 2017	
EnLink Midstream Partners, LP Performance Units:	Number of Units	Weighted Average Grant-Date Fair Value
Non-vested, beginning of period	408,637	$ 18.27
Granted	176,648	25.73
Forfeited	—	—
Non-vested, end of period	585,285	$ 20.52
Aggregate intrinsic value, end of period (in millions)	$ 9.0	

As of December 31, 2017, there was $4.8 million of unrecognized compensation expense that related to non-vested performance units. That cost is expected to be recognized over a weighted-average period of 1.8 years.

(d) EnLink Midstream, LLC's Restricted Incentive Units

ENLC restricted incentive units are valued at their fair value at the date of grant, which is equal to the market value of the ENLC common units on such date. A summary of the restricted incentive unit activity for the year ended December 31, 2017 is provided below:

	Year Ended December 31, 2017	
EnLink Midstream, LLC Restricted Incentive Units:	**Number of Units**	**Weighted Average Grant-Date Fair Value**
Non-vested, beginning of period	1,897,298	$ 19.96
Granted (1)	827,609	19.20
Vested (1)(2)	(795,032)	27.95
Forfeited	(40,565)	16.84
Non-vested, end of period	1,889,310	$ 21.64
Aggregate intrinsic value, end of period (in millions)	$ 33.3	

(1) Restricted incentive units typically vest at the end of three years. In March 2017, ENLC granted 258,606 restricted incentive units with a fair value of $5.0 million to officers and certain employees as bonus payments for 2016, and these restricted incentive units vested immediately are included in the restricted incentive units granted and vested line items.
(2) Vested units include 243,620 units withheld for payroll taxes paid on behalf of employees.

A summary of the restricted incentive units' aggregate intrinsic value (market value at vesting date) and fair value of units vested (market value at date of grant) during the years ended December 31, 2017, 2016 and 2015 is provided below (in millions):

	Year Ended December 31,		
EnLink Midstream, LLC Restricted Incentive Units:	**2017**	**2016**	**2015**
Aggregate intrinsic value of units vested	$ 15.3	$ 4.1	$ 9.2
Fair value of units vested	$ 22.2	$ 12.4	$ 9.8

As of December 31, 2017, there was $11.3 million of unrecognized compensation costs related to non-vested ENLC restricted incentive units. That cost is expected to be recognized over a weighted average period of 1.7 years.

(e) EnLink Midstream, LLC's Performance Units

In 2017, 2016 and 2015, ENLC granted performance awards under the 2014 Plan. At the end of the vesting period, recipients receive distribution equivalents, if any, with respect to the number of performance units vested. The vesting of such units ranges from zero to 200% of the units granted depending on the EnLink TSR as compared to the TSR of the Peer Companies on the vesting date. The fair value of each performance unit is estimated as of the date of grant using a Monte Carlo simulation with the following assumptions used for all performance unit grants made under the plan: (i) a risk-free interest rate based on United States Treasury rates as of the grant date; (ii) a volatility assumption based on the historical realized price volatility of ENLC's common units and the designated Peer Companies securities; (iii) an estimated ranking of ENLC among the Peer Companies and (iv) the distribution yield. The fair value of the performance unit on the date of grant is expensed over a vesting period of approximately three years.

The following table presents a summary of the grant-date fair values of performance units and the related assumptions by performance unit grant date:

EnLink Midstream, LLC Performance Units:	March 2017	October 2016	February 2016	January 2016	March 2015
Beginning TSR price	$ 18.29	$ 16.75	$ 15.38	$ 15.38	$ 34.24
Risk-free interest rate	1.62%	0.91%	0.89%	1.10%	0.99%
Volatility factor	52.07%	52.89%	52.05%	46.02%	33.02%
Distribution yield	5.40%	6.10%	14.00%	8.60%	2.98%

The following table presents a summary of the performance units:

	Year Ended December 31, 2017	
EnLink Midstream, LLC Performance Units:	Number of Units	Weighted Average Grant-Date Fair Value
Non-vested, beginning of period	384,264	$ 19.30
Granted	164,575	28.77
Forfeited	—	—
Non-vested, end of period	548,839	$ 22.14
Aggregate intrinsic value, end of period (in millions)	$ 9.7	

As of December 31, 2017, there was $5.0 million of unrecognized compensation expense that related to non-vestedperformance units. That cost is expected to be recognized over a weighted-average period of 1.8 years.

(f) Benefit Plan

ENLK maintains a tax-qualified 401(k) plan whereby it matches 100% of every dollar contributed up to 6% of an employee's salary plus a 2% non-discretionary contribution (not to exceed the maximum amount permitted by law). Contributions of $7.6 million, $7.4 million and $7.0 million were made to the plan for the years ended December 31, 2017, 2016 and 2015, respectively.

(12) Derivatives

Interest Rate Swaps

We periodically enter into interest rate swaps in connection with new debt issuances. During the debt issuance process, we are exposed to variability in future long-term debt interest payments that may result from changes in the benchmark interest rate (commonly the U.S. Treasury yield) prior to the debt being issued. In order to hedge this variability, we enter into interest rate swaps to effectively lock in the benchmark interest rate at the inception of the swap. Prior to 2017, we did not designate interest rate swaps as hedges and, therefore, included the associated settlement gains and losses as interest expense, net of interest income on the consolidated statements of operations.

In May 2017, we entered into an interest rate swap in connection with the issuance ofthe 2047 Notes. In accordance with ASC 815, we designated this swap as a cash flow hedge. Upon settlement of the interest rate swap in May 2017, we recorded the associated $2.2 million settlement loss in accumulated other comprehensive loss on the consolidated balance sheets. We will amortize the settlement loss into interest expense on the consolidated statements of operations over the term of the 2047 Notes. There was no ineffectiveness related to the hedge. We have no open interest rate swap positions as of December 31, 2017. In addition, the settlement loss is included as an operating cash outflow on the consolidated statement of cash flows for the year ended December 31, 2017.

For the year ended December 31, 2017, we amortized an immaterial amount of the settlement loss into interest expense from accumulated other comprehensive income (loss). We expect to recognize $0.1 million of interest expense out of accumulated other comprehensive income (loss) over the next twelve months.

In July 2016, we entered into an interest rate swap in connection with the issuance of the 2026 Notes. We did not designate this swap as a cash flow hedge. Upon settlement of the interest rate swap in July 2016, we recorded the associated $0.4 million gain on settlement in other income (expense) in the consolidated statement of operations for the year ended December 31, 2016.

In April and May 2015, we entered into an interest rate swap in connection with the issuance of the 2025 Notes. We did not designate this swap as a cash flow hedge. Upon settlement of the interest rate swap, we recorded the associated $3.6 million gain on settlement in other income (expense) in the consolidated statement of operations for the year ended December 31, 2015.

The impact of the interest rate swaps on net income is included in other income (expense) in the consolidated statements of operations as part of interest expense, net of interest income, as follows (in millions):

	Year Ended December 31,		
	2017	2016	2015
Settlement gains on derivatives	$ —	$ 0.4	$ 3.6

Commodity Swaps

We manage our exposure to changes in commodity prices by hedging the impact of market fluctuations. Commodity swaps are used to manage and hedge price and location risk related to these market exposures. Commodity swaps are also used to manage margins on offsetting fixed-price purchase or sale commitments for physical quantities of crude, condensate, natural gas and NGLs. We do not designate commodity swap transactions as cash flow or fair value hedges for hedge accounting treatment under ASC 815. Therefore, changes in the fair value of our derivatives are recorded in revenue in the period incurred. In addition, our risk management policy does not allow us to take speculative positions with our derivative contracts.

We commonly enter into index (float-for-float) or fixed-for-float swaps in order to mitigate our cash flow exposure to fluctuations in the future prices of natural gas, NGLs and crude oil. For natural gas, index swaps are used to protect against the price exposure of daily priced gas versus first-of-month priced gas. They are also used to hedge the basis location price risk resulting from supply and markets being priced on different indices. For natural gas, NGLs, condensate and crude, fixed-for-float swaps are used to protect cash flows against price fluctuations: (1) where we receive a percentage of liquids as a fee for processing third-party gas or where we receive a portion of the proceeds of the sales of natural gas and liquids as a fee, (2) in the natural gas processing and fractionation components of our business and (3) where we are mitigating the price risk for product held in inventory or storage.

The components of gain (loss) on derivative activity in the consolidated statements of operations related to commodity swaps are (in millions):

	Year Ended December 31,		
	2017	**2016**	**2015**
Change in fair value of derivatives	$ 4.7	$ (20.1)	$ (7.7)
Realized gain (loss) on derivatives	(8.9)	9.0	17.1
Gain (loss) on derivative activity	$ (4.2)	$ (11.1)	$ 9.4

The fair value of derivative assets and liabilities related to commodity swaps are as follows (in millions):

	December 31, 2017	**December 31, 2016**
Fair value of derivative assets — current	$ 6.8	$ 1.3
Fair value of derivative liabilities — current	(8.4)	(7.6)
Net fair value of derivatives	$ (1.6)	$ (6.3)

Assets and liabilities related to our derivative contracts are included in the fair value of derivative assets and liabilities, and the change in fair value of these contracts is recorded net as a gain (loss) on derivative activity on the consolidated statements of operations. We estimate the fair value of all of our derivative contracts based upon actively-quoted prices of the underlying commodities.

Set forth below are the summarized notional volumes and fair values of all instruments held for price risk management purposes and related physical offsets at December 31, 2017 (in millions). The remaining term of the contracts extend no later than January 2019.

		December 31, 2017		
Commodity	**Instruments**	**Unit**	**Volume**	**Fair Value**
NGL (short contracts)	Swaps	Gallons	(40.0)	$ (5.2)
NGL (long contracts)	Swaps	Gallons	23.7	1.4
Natural Gas (short contracts)	Swaps	MMBtu	(6.9)	3.8
Natural Gas (long contracts)	Swaps	MMBtu	17.3	(1.6)
Total fair value of derivatives				$ (1.6)

On all transactions where we are exposed to counterparty risk, we analyze the counterparty's financial condition prior to entering into an agreement, establish limits and monitor the appropriateness of these limits on an ongoing basis. We primarily deal with two types of counterparties, financial institutions and other energy companies, when entering into financial derivatives on commodities. We have entered into Master International Swaps and Derivatives Association Agreements ("ISDAs") that allow for netting of swap contract receivables and payables in the event of default by either party. If our counterparties failed to perform under existing swap contracts, our maximum loss of $6.8 million as of December 31, 2017 would be reduced to$1.6 million due to the offsetting of gross fair value payables against gross fair value receivables as allowed by the ISDAs.

(13) Fair Value Measurements

ASC 820, *Fair Value Measurements and Disclosures* ("ASC 820"), sets forth a framework for measuring fair value and required disclosures about fair value measurements of assets and liabilities. Fair value under ASC 820 is defined as the price at which an asset could be exchanged in a current transaction between knowledgeable, willing parties. A liability's fair value is defined as the amount that would be paid to transfer the liability to a new obligor, not the amount that would be paid to settle the liability with the creditor. Where available, fair value is based on observable market prices or parameters or derived from such prices or parameters. Where observable prices or inputs are not available, use of unobservable prices or inputs are used to estimate the current fair value, often using an internal valuation model. These valuation techniques involve some level of management estimation and judgment, the degree of which is dependent on the item being valued.

ASC 820 established a three-tier fair value hierarchy, which prioritizes the inputs used in measuring fair value. These tiers include: Level 1, defined as observable inputs such as quoted prices in active markets; Level 2, defined as inputs other than quoted prices in active markets that are either directly or indirectly observable; and Level 3, defined as unobservable inputs in which little or no market data exists, therefore requiring an entity to develop its own assumptions.

Our derivative contracts primarily consist of commodity swap contracts, which are not traded on a public exchange. The fair values of commodity swap contracts are determined using discounted cash flow techniques. The techniques incorporate Level 1 and Level 2 inputs for future commodity prices that are readily available in public markets or can be derived from information available in publicly-quoted markets. These market inputs are utilized in the discounted cash flow calculation considering the instrument's term, notional amount, discount rate and credit risk and are classified as Level 2 in hierarchy.

Net assets (liabilities) measured at fair value on a recurring basis are summarized below (in millions):

	Level 2	
	December 31, 2017	December 31, 2016
Commodity Swaps (1)	$ (1.6)	$ (6.3)

(1) The fair value of derivative contracts included in assets or liabilities for risk management activities represents the amount at which the instruments could be exchanged in a current arms-length transaction adjusted for credit risk of us and/or the counterparty as required under ASC 820.

Fair Value of Financial Instruments

The estimated fair value of our financial instruments has been determined using available market information and valuation methodologies. Considerable judgment is required to develop the estimates of fair value; thus, the estimates provided below are not necessarily indicative of the amount we could realize upon the sale or refinancing of such financial instruments (in millions):

	December 31, 2017		December 31, 2016	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Long-term debt (1)	$ 3,467.8	$ 3,575.6	$ 3,268.0	$ 3,225.8
Installment Payables	$ 249.5	$ 249.6	$ 473.2	$ 476.6
Obligations under capital lease	$ 4.1	$ 3.4	$ 6.6	$ 6.1

(1) The carrying values of long-term debt are reduced by debt issuance costs of $25.9 million and $24.1 million at December 31, 2017 and 2016, respectively. The respective fair values do not factor in debt issuance costs.

The carrying amounts of our cash and cash equivalents, accounts receivable and accounts payable approximate fair value due to the short-term maturities of these assets and liabilities.

We had no outstanding borrowings under our credit facility as of December 31, 2017 and $120.0 million in outstanding borrowings under our credit facility as of December 31, 2016. As borrowings under our credit facility accrue interest under floating interest rate structures, the carrying value of such indebtedness approximates fair value for the amounts outstanding under the credit facility. As of December 31, 2017 and 2016, we had total borrowings under senior unsecured notes of $3.5 billion and $3.1 billion, respectively with fixed interest rates ranging from 2.7% to 5.6% and 2.7% to 7.1%, respectively, maturing between 2019 and 2047. The fair value of all senior unsecured notes and installment payables as of December 31, 2017 and 2016 was based on Level 2 inputs from third-party market quotations. The fair values of obligations under capital leases were calculated using Level 2 inputs from third-party banks.

(14) Commitments and Contingencies

(a) Leases—Lessee

We have operating leases for office space, office and field equipment.

The following table summarizes our remaining non-cancelable future payments under operating leases with initial or remaining non-cancelable lease terms in excess of one year (in millions):

2018	$ 14.3
2019	10.9
2020	8.6
2021	8.6
2022	8.6
Thereafter	58.6
Total	$ 109.6

Operating lease rental expense was approximately $54.5 million, $59.6 million and $66.1 million for the years ended December 31, 2017, 2016 and 2015, respectively.

(b) Change of Control and Severance Agreements

Certain members of our management are parties to severance and change of control agreements with the Operating Partnership.The severance and change in control agreements provide those individuals with severance payments in certain circumstances and prohibit such individuals from, among other things, competing with our general partner or its affiliates during his or her employment. In addition, the severance and change of control agreements prohibit subject individuals from, among other things, disclosing confidential information about our general partner or interfering with a client or customer of our general partner or its affiliates, in each case during his or her employment and for certain periods (including indefinite periods) following the termination of such person’s employment.

(c) Environmental Issues

The operation of pipelines, plants and other facilities for the gathering, processing, transmitting, stabilizing, fractionating, storing or disposing of natural gas, NGLs, crude oil, condensate, brine and other products is subject to stringent and complex laws and regulations pertaining to health, safety and the environment. As an owner, partner or operator of these facilities, we must comply with United States laws and regulations at the federal, state and local levels that relate to air and water quality, hazardous and solid waste management and disposal, oil spill prevention, climate change, endangered species and other environmental matters. The cost of planning, designing, constructing and operating pipelines, plants, and other facilities must account for compliance with environmental laws and regulations and safety standards. Federal, state, or local administrative decisions, developments in the federal or state court systems, or other governmental or judicial actions may influence the interpretation and enforcement of environmental laws and regulations and may thereby increase compliance costs. Failure to comply with these laws and regulations may trigger a variety of administrative, civil and potentially criminal enforcement measures, including citizen suits, which can include the assessment of monetary penalties, the imposition of remedial requirements, and the issuance of injunctions or restrictions on operation. Management believes that, based on currently known information, compliance with these laws and regulations will not have a material adverse effect on our results of operations, financial condition or cash flows. However, we cannot provide assurance that future events, such as changes in existing laws, regulations, or enforcement policies, the promulgation of new laws or regulations, or the discovery or development of new factual circumstances will not cause us to incur material costs. Environmental regulations have historically become more stringent over time, and thus, there can be no assurance as to the amount or timing of future expenditures for environmental compliance or remediation.

As previously disclosed, in February 2016, a spill occurred at our Kill Buck Station in our Ohio operations. State and federal agencies were notified, and clean-up response efforts were promptly executed, which significantly lessened the impact of the spill. The state agency determined that the clean-up recovery efforts were completed and issued to us a “No Further Action” notice. We do not anticipate additional fines or penalties by either the state or federal agencies.

(d) Litigation Contingencies

We are involved in various litigation and administrative proceedings arising in the normal course of business. In the opinion of management, any liabilities that may result from these claims would not individually or in the aggregate have a material adverse effect on our financial position, results of operations or cash flows.

At times, our subsidiaries acquire pipeline easements and other property rights by exercising rights of eminent domain and common carrier. As a result, from time to time, we (or our subsidiaries) are a party to a number of lawsuits under which a court will determine the value of pipeline easements or other property interests obtained by our subsidiaries by condemnation. Damage awards in these suits should reflect the value of the property interest acquired and the diminution in the value of the remaining property owned by the landowner. However, some landowners have alleged unique damage theories to inflate their damage claims or assert valuation methodologies that could result in damage awards in excess of the amounts anticipated. Although it is not possible to predict the ultimate outcomes of these matters, we do not expect that awards in these matters will have a material adverse impact on our consolidated results of operations, financial condition or cash flows.

We own and operate a high-pressure pipeline and underground natural gas and NGL storage reservoirs and associated facilities near Bayou Corne, Louisiana. In August 2012, a large sinkhole formed in the vicinity of this pipeline and underground storage reservoirs, resulting in damage to certain of our facilities. In order to recover our losses from responsible parties, we sued the operator of a failed cavern in the area, and its insurers, as well as other parties we alleged to have contributed to the formation of the sinkhole seeking recovery for these losses. We also filed a claim with our insurers, which our insurers denied. We disputed the denial and sued our insurers, and we subsequently reached settlements regarding the entirety of our claims in both lawsuits. In August 2014, we received a partial settlement with respect to our claims in the amount of $6.1 million. We secured additional settlement payments during 2017, which resulted in the recognition of “Gain on litigation settlement” of$26.0 million on the consolidated statement of operations for the year ended December 31, 2017.

(15) Segment Information

Identification of the majority of our operating segments is based principally upon geographic regions served and the nature of operating activity. Our reportable segments consist of the following: natural gas gathering, processing, transmission and fractionation operations located in North Texas and the Permian Basin primarily in West Texas (“Texas”), the natural gas pipelines, processing plants, storage facilities, NGL pipelines and fractionation assets in Louisiana (“Louisiana”), natural gas gathering and processing operations located throughout Oklahoma (“Oklahoma”) and crude rail, truck, pipeline and barge facilities in West Texas, South Texas, Louisiana and the Ohio River Valley (“Crude and Condensate”). Operating activity for intersegment eliminations is shown in the Corporate segment. Our sales are derived from external domestic customers. We evaluate the performance of our operating segments based on segment profits.

Corporate assets consist primarily of cash,property and equipment, including software, for general corporate support, debt financing costs and unconsolidated affiliate investments in GCF and the Cedar Cove JV as of December 31, 2017 and 2016. As of December 31, 2016, our Corporate assets included our unconsolidated affiliate investment in HEP. In December 31, 2016, we entered into an agreement to sell our ownership interest in HEP, and we finalized the sale in March 2017.

Summarized financial information for our reportable segments is shown in the following tables (in millions):

	Texas	Louisiana	Oklahoma	Crude and Condensate	Corporate	Totals
Year Ended December 31, 2017						
Product sales	$ 325.0	$ 2,529.6	$ 128.8	$ 1,375.0	$ —	$ 4,358.4
Product sales—related parties	500.3	45.0	349.4	0.8	(750.6)	144.9
Midstream services	116.3	220.6	155.0	60.4	—	552.3
Midstream services—related parties	424.3	136.4	241.6	17.4	(131.5)	688.2
Cost of sales	(772.3)	(2,618.1)	(522.9)	(1,330.3)	882.1	(4,361.5)
Operating expenses	(172.7)	(101.3)	(64.6)	(80.1)	—	(418.7)
Loss on derivative activity	—	—	—	—	(4.2)	(4.2)
Segment profit (loss)	$ 420.9	$ 212.2	$ 287.3	$ 43.2	$ (4.2)	$ 959.4
Depreciation and amortization	$ (215.2)	$ (116.1)	$ (156.6)	$ (47.5)	$ (9.9)	$ (545.3)
Impairments	$ —	$ (0.8)	$ —	$ (16.3)	$ —	$ (17.1)
Goodwill	$ 232.0	$ —	$ 190.3	$ —	$ —	$ 422.3
Capital expenditures	$ 145.4	$ 75.1	$ 442.1	$ 79.1	$ 26.4	$ 768.1
Total assets	$ 3,094.8	$ 2,408.5	$ 2,836.7	$ 929.5	$ 144.5	$ 9,414.0

	Texas	Louisiana	Oklahoma	Crude and Condensate	Corporate	Totals
Year Ended December 31, 2016						
Product sales	$ 237.2	$ 1,632.5	$ 48.5	$ 1,090.7	$ —	$ 3,008.9
Product sales—related parties	287.6	57.8	120.4	1.5	(333.0)	134.3
Midstream services	104.2	215.4	82.2	65.4	—	467.2
Midstream services—related parties	439.3	95.8	185.9	18.9	(86.8)	653.1
Cost of sales	(483.4)	(1,729.0)	(184.9)	(1,038.0)	419.8	(3,015.5)
Operating expenses	(168.5)	(96.6)	(52.1)	(81.3)	—	(398.5)
Loss on derivative activity	—	—	—	—	(11.1)	(11.1)
Segment profit (loss)	$ 416.4	$ 175.9	$ 200.0	$ 57.2	$ (11.1)	$ 838.4
Depreciation and amortization	$ (196.9)	$ (114.8)	$ (140.6)	$ (42.4)	$ (9.2)	$ (503.9)
Impairments	$ (473.1)	$ —	$ —	$ (93.2)	$ —	$ (566.3)
Goodwill	$ 232.0	$ —	$ 190.3	$ —	$ —	$ 422.3
Capital expenditures	$ 217.9	$ 79.1	$ 295.7	$ 74.3	$ 9.1	$ 676.1
Total assets	$ 3,142.6	$ 2,349.3	$ 2,524.5	$ 836.8	$ 300.2	$ 9,153.4

ENLINK MIDSTREAM PARTNERS, LP
Notes to Consolidated Financial Statements (Continued)

	Texas	Louisiana	Oklahoma	Crude and Condensate	Corporate	Totals
Year Ended December 31, 2015						
Product sales	$ 320.0	$ 1,527.7	$ 5.0	$ 1,401.0	$ —	$ 3,253.7
Product sales—related parties	123.3	48.5	13.0	0.8	(66.2)	119.4
Midstream services	100.2	244.1	28.3	78.4	—	451.0
Midstream services—related parties	456.7	20.0	140.7	18.0	(16.8)	618.6
Cost of sales	(412.2)	(1,567.6)	(17.9)	(1,330.6)	83.0	(3,245.3)
Operating expenses	(181.8)	(105.9)	(30.3)	(101.9)	—	(419.9)
Gain on derivative activity	—	—	—	—	9.4	9.4
Segment profit	$ 406.2	$ 166.8	$ 138.8	$ 65.7	$ 9.4	$ 786.9
Depreciation and amortization	$ (169.7)	$ (109.1)	$ (49.8)	$ (51.5)	$ (7.2)	$ (387.3)
Impairments	$ (496.3)	$ (787.3)	$ (0.6)	$ (279.2)	$ —	$ (1,563.4)
Goodwill	$ 703.5	$ —	$ 190.3	$ 93.2	$ —	$ 987.0
Capital expenditures	$ 268.0	$ 59.2	$ 40.7	$ 187.5	$ 15.1	$ 570.5
Total assets	$ 3,709.5	$ 2,309.3	$ 873.4	$ 898.0	$ 302.6	$ 8,092.8

The following table reconciles the segment profits reported above to the operating income (loss) as reported on the consolidated statements of operations (in millions):

	Year Ended December 31,		
	2017	2016	2015
Segment profits	$ 959.4	$ 838.4	$ 786.9
General and administrative expenses	(123.5)	(119.3)	(132.4)
Depreciation and amortization	(545.3)	(503.9)	(387.3)
Loss on disposition of assets	—	(13.2)	(1.2)
Impairments	(17.1)	(566.3)	(1,563.4)
Gain on litigation settlement	26.0	—	—
Operating income (loss)	$ 299.5	$ (364.3)	$ (1,297.4)

(16) Quarterly Financial Data (Unaudited)

Summarized unaudited quarterly financial data is presented below (in millions, except per unit data):

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total
2017					
Revenues	$ 1,321.9	$ 1,263.6	$ 1,397.9	$ 1,756.2	$ 5,739.6
Impairments	$ 7.0	$ —	$ 1.8	$ 8.3	$ 17.1
Operating income	$ 57.6	$ 70.4	$ 73.4	$ 98.1	$ 299.5
Net income attributable to EnLink Midstream Partners, LP	$ 18.1	$ 29.6	$ 25.5	$ 75.7	$ 148.9
General partner interest in net income	$ 5.9	$ 10.8	$ 10.6	$ 11.0	$ 38.3
Limited partners' interest in net income (loss) attributable to EnLink Midstream Partners, LP	$ (9.3)	$ (0.5)	$ (8.6)	$ 36.3	$ 17.9
Net income (loss) attributable to EnLink Midstream Partners, LP per limited partners' unit:					
Basic common unit	$ (0.03)	$ —	$ (0.02)	$ 0.10	$ 0.05
Diluted common unit	$ (0.03)	$ —	$ (0.02)	$ 0.10	$ 0.05
2016					
Revenues	$ 889.7	$ 1,033.2	$ 1,104.6	$ 1,224.9	$ 4,252.4
Impairments	$ 566.3	$ —	$ —	$ —	$ 566.3
Operating income (loss)	$ (515.9)	$ 46.4	$ 66.9	$ 38.3	$ (364.3)
Net income (loss) attributable to EnLink Midstream Partners, LP	$ (560.4)	$ 5.0	$ 18.8	$ (28.6)	$ (565.2)
General partner interest in net income	$ 7.4	$ 10.6	$ 10.8	$ 10.7	$ 39.5
Limited partners' interest in net loss attributable to EnLink Midstream Partners, LP	$ (567.2)	$ (23.5)	$ (11.4)	$ (60.0)	$ (662.1)
Net income (loss) attributable to EnLink Midstream Partners, LP per limited partners' unit:					
Basic common unit	$ (1.74)	$ (0.07)	$ (0.03)	$ (0.18)	$ (1.99)
Diluted common unit	$ (1.74)	$ (0.07)	$ (0.03)	$ (0.18)	$ (1.99)
2015					
Revenues	$ 940.5	$ 1,274.5	$ 1,170.6	$ 1,066.5	$ 4,452.1
Impairments	$ —	$ —	$ 799.2	$ 764.2	$ 1,563.4
Operating income (loss)	$ 51.5	$ 72.5	$ (730.5)	$ (690.9)	$ (1,297.4)
Net income (loss) attributable to EnLink Midstream Partners, LP	$ 35.6	$ 55.5	$ (754.9)	$ (714.0)	$ (1,377.8)
General partner interest in net income	$ 26.5	$ 19.1	$ 6.3	$ 6.1	$ 58.0
Limited partners' interest in net income (loss) attributable to EnLink Midstream Partners, LP	$ 9.0	$ 35.7	$ (745.2)	$ (704.7)	$ (1,405.2)
Net income (loss) attributable to EnLink Midstream Partners, LP per limited partners' unit:					
Basic common unit	$ 0.03	$ 0.12	$ (2.32)	$ (2.17)	$ (4.66)
Diluted common unit	$ 0.03	$ 0.12	$ (2.32)	$ (2.17)	$ (4.66)

(17) Supplemental Cash Flow Information

The following schedule summarizes non-cash financing activities for the periods presented (in millions):

	Year Ended December 31,		
Non-cash financing activities:	**2017**	**2016**	**2015**
Installment payable, net of discount of $79.1 million (1)	$ —	$ 420.9	$ —
Contribution from ENLC (2)	—	237.1	—
Non-cash issuance of common units (3)	—	—	180.0
Non-cash issuance of Class C common units (3)	—	—	180.0
Non-cash adjustment of interest in Midstream Holdings (4)	—	—	66.5

(1) We incurred installment purchase obligations, net of discount, payable to the seller in connection with the EnLink Oklahoma T.O. assets. We paid the second and final installments during January 2017 and 2018, respectively. See "Note 3—Acquisitions" for further discussion.
(2) Contribution from ENLC in connection with the acquisition of the EnLink Oklahoma T.O assets. See "Note 3—Acquisitions" for further discussion.
(3) Non-cash common units and Class C Common Units were issued as partial consideration for the Coronado acquisition. See "Note 3—Acquisitions" for further discussion.
(4) Non-cash adjustment to reflect recast of Midstream Holdings' interests acquired on February 17, 2015 and May 27, 2015. See "Note 1—Organization and Summary of Significant Agreements" for further discussion.

(18) Other Information

The following table present additional detail for other current assets and other current liabilities, which consists of the following (in millions):

Other Current Assets:	**December 31, 2017**	**December 31, 2016**
Natural gas and NGLs inventory	$ 30.1	$ 17.4
Prepaid expenses and other	9.6	13.6
Natural gas and NGLs inventory, prepaid expenses and other	$ 39.7	$ 31.0

Other Current Liabilities:	**December 31, 2017**	**December 31, 2016**
Accrued interest	$ 35.4	$ 34.2
Accrued wages and benefits, including taxes	30.4	19.0
Accrued ad valorem taxes	27.8	23.5
Capital expenditure accruals	48.8	64.6
Onerous performance obligations	15.2	15.9
Other	64.8	59.8
Other current liabilities	$ 222.4	$ 217.0

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

None.

Item 9A. Controls and Procedures

(a) Evaluation of Disclosure Controls and Procedures

We carried out an evaluation, under the supervision and with the participation of management, including the Chief Executive Officer and Chief Financial Officer of EnLink Midstream GP, LLC, of the effectiveness of our disclosure controls and procedures as of the end of the period covered by this report pursuant to Exchange Act Rules 13a-15 and 15d-15. Based on that evaluation, the Chief Executive Officer and Chief Financial Officer have concluded that, as of the end of the period covered by this report (December 31, 2017), our disclosure controls and procedures were effective to provide reasonable assurance that information required to be disclosed by us in the reports we file or submit under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported, within the time period specified in the applicable rules and forms, and that such information is accumulated and communicated to management, including our Chief Executive Officer and Chief Financial Officer, to allow timely decisions regarding disclosure.

(b) Changes in Internal Control Over Financial Reporting

There has been no change in our internal control over financial reporting that occurred in the three months ended December 31, 2017 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

Internal Control Over Financial Reporting

See “Item 8. Financial Statements and Supplementary Data—Management’s Report on Internal Control over Financial Reporting.”

Item 9B. Other Information

None.

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PART III

Item 10. Directors, Executive Officers and Corporate Governance

We are managed by the board of directors and executive officers of EnLink Midstream GP, LLC, our general partner. Our general partner is not elected by our unitholders and will not be subject to re-election by our unitholders in the future. Our general partner has a board of directors, and our common unitholders are not entitled to elect the directors or to participate directly or indirectly in our management or operations. Our operational personnel are employees of EnLink Midstream Operating, LP (the “Operating Partnership”). References to our officers, directors and employees are references to the officers, directors and employees of our general partner or the Operating Partnership.

Our general partner will be liable, as general partner, for all of our debts (to the extent not paid from our assets), except for indebtedness or other obligations that are entered into and specified as nonrecourse to our general partner. Whenever possible, we intend to incur indebtedness that is nonrecourse to our general partner.

The following table shows information for the members of the board of directors (the “Board”)and the executive officers of our general partner. Executive officers and directors serve until their successors are duly appointed or elected.

Name	Age	Position with EnLink Midstream GP, LLC
Michael J. Garberding	49	President and Chief Executive Officer and Director
Eric D. Batchelder	46	Executive Vice President and Chief Financial Officer
McMillan (Mac) Hummel	55	Executive Vice President and President of Natural Gas Liquids and Crude
Benjamin D. Lamb	38	Executive Vice President, North Texas and Oklahoma (1)
Alaina K. Brooks	43	Senior Vice President, General Counsel and Secretary
Barry E. Davis	56	Director and Executive Chairman of the Board
Leldon E. Echols (2)	62	Director and Member of the Audit Committee (3)
Scott A. Griffiths (2)	63	Director and Member of the Compensation (3) and Conflicts Committees
David A. Hager	61	Director and Member of the Compensation Committee
Mary P. Ricciardello (2)	62	Director and Member of the Audit Committee
Kyle D. Vann (2)	70	Director and Member of the Conflicts (3) and Audit Committees
Kevin D. Lafferty	42	Director
R. Alan Marcum	51	Director
Christopher Ortega	42	Director
Jeff L. Ritenour	44	Director
Lyndon Taylor	58	Director
Tony Vaughn	60	Director

(1) In February 2018, the Board appointed Mr. Lamb to Executive Vice President, North Texas and Oklahoma. Prior to February 2018, Mr. Lamb served as Executive Vice President, Corporate Development.
(2) Independent director.
(3) Chairman of committee.

Michael J. Garberding, President and Chief Executive Officer and Director, joined our general partner in February 2008. Mr. Garberding was appointed President and Chief Executive Officer effective January 2, 2018. Previously, Mr. Garberding assumed the role of President and Chief Financial Officer in September 2016, Executive Vice President and Chief Financial Officer in January 2013 and Senior Vice President and Chief Financial Officer in August 2011. Mr. Garberding previously led our finance and business development organization. Mr. Garberding has 25 years of experience in finance and accounting. From 2002 to 2008, Mr. Garberding held various finance and business development positions at TXU Corporation, including assistant treasurer. In addition, Mr. Garberding worked at Enron North America as a Finance Manager and Arthur Andersen LLP as an Audit Manager. He received his Master of Business Administration from the University of Michigan in 1999 and his Bachelor of Business Administration in accounting from Texas A&M University in 1991. Mr. Garberding was selected to serve as a director due to, among other factors, his accounting and financial experience, his leadership skills, and his experience in the midstream industry.

Eric D. Batchelder, Executive Vice President and Chief Financial Officer, joined our general partner in January 2018. Prior to joining our general partner, Mr. Batchelder served five years as Managing Director, Energy Investment Banking at RBC Capital Markets. At RBC, he was responsible for maintaining key client relationships, strategic planning, and business development efforts for the bank's midstream energy advisory business in the United States. Previously, Mr. Batchelder spent 10 years at Goldman Sachs & Co. Prior to that, he spent seven years at Arthur Andersen LLP. Mr. Batchelder has over 15 years of strategic M&A and capital markets experience in the energy sector. Mr. Batchelder is a Certified Public Accountant. He earned a Bachelor of Arts in economics from Middlebury College, a Master of Science in professional accounting from the University of Hartford and a Master of Business Administration from The Tuck School of Business at Dartmouth.

McMillan (Mac) Hummel, Executive Vice President and President of Natural Gas Liquids and Crude, joined our general partner in March 2014. Previously, Mr. Hummel served in various positions with The Williams Companies, which he joined in 1985, including Vice President of Commodity Services, Vice President of Natural Gas Liquids and Petchem Services and Vice President of Western Region Gathering and Processing. Mr. Hummel began his career with Williams' Northwest Pipeline while living in Salt Lake City, Utah. Mr. Hummel also served as Director of Business Development for Williams while living in Calgary, Alberta. Mr. Hummel has been a member of the American Fuel & Petrochemical Manufacturers Petrochemical Committee, the Association of Oil Pipe Lines Pipeline Subcommittee and the board of Aux Sable Liquids Partners. Mr. Hummel earned a Bachelor of Science in accounting and a Master of Business Administration from the University of Utah.

Benjamin D. Lamb, Executive Vice President, North Texas and Oklahoma, joined our general partner in December 2012. Mr. Lamb assumed his current role in February 2018, having previously served as Executive Vice President, Corporate Development, Vice President of Finance and Senior Vice President of Finance and Corporate Development. Prior to joining our general partner, Mr. Lamb served as a Principal at the investment banking firm Greenhill & Co., which he joined in 2005. In that role, he focused on the evaluation and execution of mergers, acquisitions and restructuring transactions for clients primarily in the midstream energy, power and utility industries. Prior to joining Greenhill, he served as an investment banker at UBS Investment Bank in its Mergers and Acquisitions Group and in its Global Energy Group, and at Merrill Lynch in its Global Energy and Power Group. Mr. Lamb received his Bachelor of Business Administration from Baylor University in 2000.

Alaina K. Brooks, Senior Vice President, General Counsel and Secretary, joined our general partner in 2008. Ms. Brooks has served in several legal roles within our company, most recently as Deputy General Counsel before assuming the role of Senior Vice President, General Counsel and Secretary in September 2014. In Ms. Brooks' current role, she serves on our Senior Leadership Team and leads the legal, regulatory, public and industry affairs, and the environmental health and safety functions. Before joining our general partner in 2008, Ms. Brooks practiced law at Weil, Gotshal & Manges LLP and Baker Botts LLP, where she counseled clients on matters of complex commercial litigation, risk management and taxation. Ms. Brooks is a licensed Certified Public Accountant and holds a Juris Doctor from Duke University School of Law and Bachelor of Science and Master of Science in accounting from Oklahoma State University.

Barry E. Davis, Executive Chairman, led the management buyout of the midstream assets of Comstock Natural Gas, Inc. in December 1996, which resulted in the formation of Crosstex Energy, Inc. Mr. Davis was appointed to Executive Chairman effective January 2, 2018. Previously, Mr. Davis served as Chairman and Chief Executive Officer from June 2016 until January 1, 2018 and as President and Chief Executive Officer from our formation until June 2016. Mr. Davis has served as a director since our initial public offering in December 2002. Mr. Davis was President and Chief Operating Officer of Comstock Natural Gas and founder of Ventana Natural Gas, a gas marketing and pipeline company that was purchased by Comstock Natural Gas. Mr. Davis started Ventana Natural Gas in June 1992. Prior to starting Ventana, he was Vice President of Marketing and Project Development for Endevco, Inc. Before joining Endevco, Mr. Davis was employed by Enserch Exploration in the marketing group. Mr. Davis holds a Bachelor of Business Administration in Finance from Texas Christian University. Mr. Davis's leadership skills and experience in the midstream natural gas industry, among other factors, led the Company Board to conclude that he should serve as Executive Chairman of the Board.

Leldon E. Echols joined Crosstex Energy, Inc. as a director in January 2008. Mr. Echols is a private investor. Mr. Echols also currently serves as an independent director of Trinity Industries, Inc. and HollyFrontier Corporation, an independent petroleum refiner and marketer. Mr. Echols brings 30 years of financial and business experience to the Board. After 22 years with the accounting firm Arthur Andersen LLP, which included serving as managing partner of the firm's audit and business advisory practice in North Texas, Colorado and Oklahoma, Mr. Echols spent six years with Centex Corporation as executive vice president and chief financial officer. He retired from Centex Corporation in June 2006. Mr. Echols previously served as a member of the board of directors of Roofing Supply Group Holdings, Inc., a private company. He also served on the board of TXU Corporation where he chaired the Audit Committee and was a member of the Strategic Transactions Committee until the completion of the private equity buyout of TXU in October 2007. Mr. Echols earned a Bachelor of Science in accounting from Arkansas State University. He is a member of the American Institute of Certified Public Accountants and the Texas Society of

CPAs. Mr. Echols was selected to serve as a director due to his accounting and financial experience and service as the chief financial officer for another public company, among other factors.

Scott A. Griffiths has been an independent oil and gas consultant since 2007, advising clients on various Gulf of Mexico investment opportunities. Prior to that, he served as Senior Vice President and Chief Operating Officer of Hydro Gulf of Mexico, LLC until December 2006. Mr. Griffiths was Executive Vice President and Chief Operating Officer of Spinnaker Exploration Company and also served in senior management and exploration roles at Ocean Energy, Inc., Global Natural Resources, Inc. and Shell Oil Company. Mr. Griffiths has served as a director of our general partner since completion of the Business Combination. Mr. Griffiths served as a director on the Board of Copano Energy, LLC until it was acquired by Kinder Morgan Energy Partners in 2013 and also served as a director on the Board of Energy XXI Ltd. until December 31, 2016. He holds a Bachelor of Science in Geology from the University of New Mexico, a Master of Science in Geology from Indiana University and completed the Advanced Management Program at Harvard Business School. Mr. Griffiths was selected to serve as a director due to his extensive experience in the energy industry, his knowledge of oil and gas exploration and his business expertise.

David A. Hager has served as the President and Chief Executive officer of Devon since August 2015. Prior to that, Mr. Hager served as Chief Operating Officer of Devon since June 2013. He joined Devon in 2009 as Executive Vice President of Exploration and Production. Prior to Devon, Mr. Hager held several positions within Kerr-McGee Corp, most recently as Chief Operating Officer in the period just before its merger with Anadarko Petroleum. Mr. Hager was a Director and Chairman of the Reserves Committee on Devon's Board from 2007 until 2009 and has served as a director for Pride International, Inc. Mr. Hager holds a Bachelor of Science in Geophysics from Purdue University and a Master of Science in Business Administration from Southern Methodist University. Mr. Hager was selected to serve as a director due to his affiliation with Devon, his knowledge of the energy business and his business expertise.

Mary P. Ricciardello was Senior Vice President and Chief Accounting Officer at Reliant Energy Inc., a leading independent power producer and marketer until 2002. She began her career with Reliant in 1982 and served in various financial management positions with the company, including Comptroller, Senior Vice President and Chief Accounting Officer. Ms. Ricciardello has served as a director of our general partner since March 2014. Ms. Ricciardello also serves as a director on the boards of Devon and Noble Corporation and has served as a director on the Board of Midstates until March 2015. Ms. Ricciardello is also a NACD Board Leadership Fellow. Ms. Ricciardello holds a Bachelor of Science in Business Administration from the University of South Dakota and a Master of Science in Business Administration with an emphasis in Finance from the University of Houston. She is a licensed Certified Public Accountant. Ms. Ricciardello was selected to serve as a director due to her qualifications as a financial expert and her extensive experience in the energy industry, as well as corporate finance and tax matters.

Kyle D. Vann joined our general partner as a director in April 2006. Mr. Vann began his career with Exxon Corporation in 1969. After ten years at Exxon, he joined Koch Industries and served in various leadership capacities, including senior vice president from 1995-2000. In 2001, he then took on the role of CEO of Entergy-Koch, LP, an energy trading and transportation company, which was sold in 2004. Currently, Mr. Vann continues to consult with Entergy and was an executive advisor to CCMP Capital Advisors, LLC from 2012-2017. He also serves on the boards of Texon, L.P., PQ Chemical and Legacy Reserves, LLC (NASDAQ: LGCY). He also serves as a director on the Boards of Mars Hill Productions and Generous Giving, which are private, charitable non-profits. Mr. Vann graduated from the University of Kansas with a Bachelor of Science in chemical engineering. He is a member of the Board of Advisors for the University of Kansas School of Engineering (where he was a recipient of the Distinguished Engineering Service Award). Mr. Vann was selected to serve as a director due to his extensive experience in the energy industry and his business expertise, among other factors.

Kevin D. Lafferty is Senior Vice President of Commercial and U.S. Operations of Devon, a position he has served in since April 2017. Mr. Lafferty oversees Devon's Marketing, Supply Chain, Strategic Planning and EHS functions along with the North Texas and Southern business units. Mr. Lafferty previously served in roles at Devon of increasing responsibility, most recently as Senior Vice President of U.S. Operations. Prior to joining Devon in 2009, Mr. Lafferty worked for ConocoPhillips and Enbridge Inc. Mr. Lafferty holds a Bachelor of Science in chemical engineering from the University of Kansas. Mr. Lafferty serves on the boards of Youth and Family Services, Inc. and the Oklahoma City Ballet, and on the Advisory Board of the University of Kansas Department of Chemical and Petroleum Engineering. Mr. Lafferty was selected to serve as a director due to his affiliation with Devon, his knowledge of the energy business, and his financial and business expertise.

R. Alan Marcum was elected to the position of Executive Vice President Administration of Devon in 2008, and has been with Devon since 1995. Prior to joining Devon, Mr. Marcum was employed by KPMG Peat Marwick (now KPMG LLP) as a Senior Auditor. He earned a Bachelor of Science in accounting and finance from East Central University. Mr. Marcum is a

Certified Public Accountant and a member of the Oklahoma Society of Certified Public Accountants. Mr. Marcum was selected to serve as a director due to his affiliation with Devon, his knowledge of the energy business, and his financial and business expertise.

Christopher Ortega joined our general partner as a director in January 2016. Mr. Ortega is a Partner of TPG. He has over 10 years of experience in the energy sector and currently sits on the board of Jonah Energy and is a director of the general partner of Axip Energy Services, LP (formerly known as Valerus Compression Services, LP). Mr. Ortega has previously served on the boards of AMCI Capital, Barra Energia, Connect Resource Services, DOF Subsea, and LMP Exploration. Mr. Ortega's responsibilities encompass investment origination, structuring, execution, monitoring, and exit strategy. He has a particular focus on the upstream oil and gas, oilfield services, and midstream sectors. Prior to TPG Capital, Mr. Ortega was a director at First Reserve Corporation. Mr. Ortega received his Bachelor of Arts, Magna cum laude, from Harvard University, a Master of Business Administration from Harvard Business School and graduated Magna cum laude from Harvard Law School. Mr. Ortega was selected as a director pursuant to a Board Representation Agreement entered into on January 7, 2016 between us, our general partner, EMI and TPG VII Management, LLC, an affiliate of Enfield Holdings, L.P., the purchaser in the private placement consummated on January 7, 2016. Mr. Ortega brings to the Board investment, financial and industry experience.

Jeff L. Ritenour was elected to the position of Executive Vice President and Chief Financial Officer of Devon on April 19, 2017. He has been with Devon since 2001, serving in various leadership roles, including most recently as Senior Vice President Corporate Finance, Investor Relations and Treasurer. Prior to joining Devon, Mr. Ritenour was an auditor with the firm of Ernst & Young. He earned both a Bachelor of Business Administration in accounting and a Master of Business Administration from the University of Oklahoma and is a member of the Oklahoma Society of Certified Public Accountants. Mr. Ritenour was selected to serve as a director due to his affiliation with Devon, his knowledge of the energy business, and his financial and business expertise.

Lyndon Taylor was elected to the position of executive vice president and general counsel for Devon in February 2007. Mr. Taylor had served as Devon's deputy general counsel since August 2005. Prior to joining Devon, Taylor was with Skadden, Arps, Slate, Meagher & Flom, LLP for 20 years and served as managing partner of the firm's Houston office from 1993 to 2005. He is admitted to practice law in Oklahoma and Texas. Taylor received his Bachelor of Science in industrial engineering from Oklahoma State University and his law degree from the University of Oklahoma. Mr. Taylor was selected to serve as a director due to his affiliation with Devon, his knowledge of the energy business, and his financial and business expertise.

Tony Vaughn joined our general partner as a director in January 2016. Mr. Vaughnis employed by Devon, and he was elected to the position of Executive Vice President of Exploration and Production of Devon in 2013. From 1999 until 2013, Mr. Vaughn served in various positions at Devon, including most recently as Senior Vice President of Exploration and Production and Strategic Services. Before joining Devon in 1999, Mr. Vaughn spent 12 years with Kerr-McGee Corporation, most recently as Manager of the Rocky Mountain District. He holds a Bachelor of Science in Petroleum Engineering from the University of Tulsa and Bachelor of Science in Business Management from Oral Roberts University. He is a member of the Society of Petroleum Engineers. Mr. Vaughn was selected to serve as a director due to his affiliation with Devon, his knowledge of the energy business and his business expertise.

Independent Directors

Because we are a limited partnership, the NYSE does not require the Board to be composed of a majority of directors who meet the criteria for independence required by the NYSE or to maintain nominating/corporate governance and compensation committees composed entirely of independent directors. Our Board has adopted Governance Guidelines that require at least three members of our Board to be independent directors as defined by the rules of the NYSE.

For a director to be "independent" under the NYSE standards, the Board must affirmatively determine that the director has no material relationship with the Partnership (either directly or as a partner, shareholder or officer of any organization that has a relationship with the Partnership, other than in his or her capacity as a director of the Partnership). In addition, the director must meet certain independence standards specified by the NYSE, including a requirement that the director was not employed by our general partner or engaged in certain business dealings with our general partner. Using these standards for determining independence, the Board has determined that Messrs. Echols, Vann, Griffiths and Ms. Ricciardello qualify as "independent" directors.

In addition, the members of the Audit Committee of our Board each qualify as "independent" under special standards established by the Securities and Exchange Commission ("SEC") for members of audit committees, and the Audit Committee includes at least one member who is determined by our Board to meet the qualifications of an "audit committee financial expert" in accordance with SEC rules, including that the person meets the relevant definition of an "independent" director. Mr. Echols and Ms. Ricciardello are both independent directors who have been determined to be audit committee financial experts. Unitholders should understand that this designation is a disclosure requirement of the SEC related to their experience and understanding with respect to certain accounting and auditing matters. The designation does not impose on such directors any duties, obligations or liabilities that are greater than are generally imposed on them as members of the Audit Committee and the Board, and the designation of a director as audit committee financial experts pursuant to this SEC requirement does not affect the duties, obligations or liabilities of any other member of the Audit Committee or the Board. Additionally, the Board has determined that the simultaneous service by Mr. Echols and Ms. Ricciardello on the Audit Committees of three other publicly traded companies on which they serve does not impair their ability to effectively serve on the Audit Committee of our general partner.

Board Committees

The Board has, and appoints the members of, standing Audit, Conflicts, Pricing and Compensation Committees. Each member of the Audit, Compensation and Conflicts Committees is an independent director in accordance with the NYSE standards described above. Each of the board committees, other than the Pricing Committee, has a written charter approved by the Board. Copies of the charters and our Code of Business Conduct and Ethics are available to any person, free of charge, at our website: www.enlink.com.

The Audit Committee, comprised of Messrs. Echols (chair), Vann and Ms. Ricciardello, assists the Board in its general oversight of our financial reporting, internal controls and audit functions, and is directly responsible for the appointment, retention, compensation and oversight of the work of our independent auditors.

The Conflicts Committee, comprised of Messrs. Vann (chair) and Griffiths, reviews specific matters that the Board believes may involve conflicts of interest. The Conflicts Committee determines if the resolution of a conflict of interest is fair and reasonable to us. The members of the Conflicts Committee are not directors, officers or employees of EnLink Midstream, LLC, the owner of our general partner. Any matters approved by the Conflicts Committee will be conclusively deemed to be fair and reasonable to us, approved by all of our partners and not a breach by our general partner of any duties owed to us or our unitholders.

The Compensation Committee, comprised of Messrs. Griffiths (chair) and Hager, oversees compensation decisions for the officers of our general partner as well as the compensation plans described herein.

In addition, the Board has established a standing Shelf Pricing Committee comprised of Messrs. Davis and Garberding, as directors, to determine the terms and conditions of any registered offering of our common units or other equity securities. There is no requirement for directors who serve on the Pricing Committee to be independent.

Board Meetings and Attendance

Our Board met 11 times in 2017. None of our incumbent directors attended fewer than 75% of the total number of meetings of our Board and committees of our Board on which they served.

The non-management directors meet in executive session without management participation at least quarterly. The non-management directors present at such executive sessions designate a director to preside at such meetings (the "Presiding Non-Management Director"). Unitholders or interested parties may communicate with non-management directors by sending written communications to the following address to the attention of the Presiding Non-Management Director: EnLink Midstream Partners, LP, 1722 Routh St., Suite 1300, Dallas, Texas 75201.

Code of Ethics and Governance Guidelines

Our general partner has adopted a Code of Business Conduct and Ethics (the "Code of Ethics") applicable to all of our employees, officers and directors with regard to Partnership-related activities. The Code of Ethics incorporates guidelines designed to deter wrongdoing and to promote honest and ethical conduct and compliance with applicable laws and regulations. It also incorporates expectations of our employees that enable us to provide accurate and timely disclosure in our filings with the SEC and other public communications. Our general partner has also adopted Governance Guidelines that outline the important policies and practices regarding our governance and provide an effective framework for the functioning of our Board and its committees. A copy of the Code of Ethics and the Governance Guidelines are available to any person, free of charge, within the "Governance Documents" subsection of the "Corporate Governance" section of the investors section of our website at www.enlink.com. If any substantive amendments are made to the Code of Ethics or if we or our general partner grants any waiver, including any implicit waiver, from a provision of the Code of Ethics to any of our general partner's executive officers and directors, we will disclose the nature of such amendment or waiver on our website. The information contained on, or connected to, our website is not incorporated by reference into this Annual Report on Form 10-K and should not be considered part of this or any other report that we file with or furnish to the SEC.

Section 16(a)—Beneficial Ownership Reporting Compliance

Section 16(a) of the Securities Exchange Act of 1934 requires our directors, executive officers and 10% unitholders to file with the SEC reports of ownership and changes in ownership of our equity securities. Based solely upon a review of the copies of the Forms 3, 4 and 5 reports furnished to us and written representations from our directors and executive officers, we believe that during 2017, all of our directors, executive officers and beneficial owners of more than 10% of our common units complied with Section 16(a) filing requirements applicable to them, other than one Form 4 for each of TPG Advisors VII, Inc. and Enfield Holding Advisors, Inc., which control Enfield Holdings, L.P., which forms were filed one day late.

Reimbursement of Expenses of our General Partner and its Affiliates

Our general partner does not receive any management fee or other compensation in connection with its management of our partnership. However, our general partner performs services for us and is reimbursed by us for all expenses incurred on our behalf, including the costs of employee, officer and director compensation and benefits, as well as all other expenses necessary or appropriate to the conduct of our business. The partnership agreement provides that our general partner will determine the expenses that are allocable to us in any reasonable manner determined by our general partner in its sole discretion.

Item 11. Executive Compensation

Compensation Committee Report

Each member of the Compensation Committee is an independent director in accordance with NYSE standards. TheCompensation Committee has reviewed and discussed with management the following section titled "Compensation Discussion and Analysis." Based upon its review and discussions, the Compensation Committee has recommended to the Board that the Compensation Discussion and Analysis be included in this Annual Report on Form 10-K.

By the Members of the Compensation Committee:

Scott A. Griffiths (Chairman)

David A. Hager

Compensation Discussion and Analysis

The following Compensation Discussion and Analysis provides an overview of the philosophy and objectives of our executive compensation program. It explains how compensation decisions are linked to performance as compared to our strategic goals and defined targets under the elements of the compensation program. These goals and targets are disclosed in the limited context of our compensation programs and should not be understood to be statements of management's expectations or estimates of results or other guidance.

Overview

We do not directly employ any of the persons responsible for managing our business.EnLink Midstream GP, LLC, our general partner,manages our operations and activities, and its board of directors (the "Board") and officers make decisions on our behalf. The compensation of the named executive officers of EnLink Midstream GP, LLC is determined by the Board upon the recommendation of itsCompensation Committee. Our named executive officers also serve as named executive officers of ENLC and the compensation of the named executive officers discussed below reflects total compensation for services with respect to ENLC and all subsidiaries of ENLC. We pay or reimburse all expenses incurred on our behalf, including the costs of employee, officer and director compensation and benefits, as well as all other expenses necessary or appropriate to the conduct of our business. Our partnership agreement provides that our general partner will determine the expenses allocable to us in any reasonable manner determined by our general partner in its sole discretion. ENLC currently pays a monthly fee to EnLink

Midstream GP, LLC to cover its portion of administrative and compensation costs, including compensation costs relating to the named executive officers.

Based on the information that we track regarding the amount of time spent by each of our named executive officers on business matters relating to ENLK, we estimate that such officers devoted the following percentage of their time to the business of ENLK and ENLC for 2017:

Executive Officer	Percentage of Time Devoted to Business of ENLK	Percentage of Time Devoted to Business of ENLC
Michael J. Garberding (1)	60%	40%
Mac Hummel	90%	10%
Benjamin D. Lamb	90%	10%
Barry E. Davis (1)	80%	20%
Steve J. Hoppe (2)	90%	10%

(1) In January 2018, the Board appointed Mr. Davis to Executive Chairman of the Board, Mr. Garberding to President and Chief Executive Officer and Mr. Batchelder to Executive Vice President and Chief Financial Officer. Prior to January 2018, Mr. Davis served as Chief Executive Officer and Chairman of the Board, and Mr. Garberding served as President and Chief Financial Officer.

(2) In January 2018, Mr. Hoppe resigned from his position as Executive Vice President and President of Gas Gathering, Processing and Transmission.

Compensation Philosophy and Principles

Our executive compensation program is designed to attract, retain and motivate highly qualified executives and align their individual interests with the interests of our unitholders. It is the Compensation Committee's responsibility to design and administer compensation programs that achieve these goals, and to make recommendations to the Board to approve and adopt these programs. The compensation of each of our executives is primarily comprised of base salary, annual bonus, and equity-based awards under our long-term incentive plans. The Compensation Committee's philosophy is to generally target the 50th percentile of our Peer Group (discussed below) for base salary and bonus (but retain discretion to reduce or increase bonus amounts to address individual performance) and to provide executives the opportunity to earn long-term incentive compensation, in the form of equity, targeted at the 75th percentile of our Peer Group.

The Compensation Committee considers the following principles in determining the total compensation of the named executive officers:

- Base salary, short-term incentives and long-term incentives should be competitive with the market in which we compete for executive talent in order to attract, retain and motivate highly qualified executives;

- Equity-based awards under the long-term incentive plans should represent a significant portion of the executive's total compensation in order to retain and incentivize highly qualified executives and align their individual long-term interests with the interests of unitholders;

- The compensation program should be sufficiently flexible to address special circumstances, which include payments under retention plans specifically targeted to retain highly qualified executives during challenging times; and

- The compensation program should drive performance and reward contributions in support of our business strategies and achievements.

Compensation Methodology

Annually, the Compensation Committee reviews our executive compensation program and each individual element of compensation. The review includes an analysis of the compensation practices of other companies in our industry, the competitive market for executive talent, the evolving demands of the business, specific challenges that we may face and individual contributions to us and our general partner. The Compensation Committee recommends to the Board adjustments to the compensation program and to each individual element as determined necessary to achieve our goals. The Compensation

Committee retains compensation consultants to assist in its review and to provide input regarding the compensation program and each individual element.

Role of Compensation Consultant

The Compensation Committee has retained Meridian Compensation Partners, LLC ("Meridian") as its independent compensation consultant to conduct a compensation review and advise the Compensation Committee on certain matters relating to compensation programs applicable to the named executive officers and other employees ofour general partner. In particular, Meridian has assisted the Compensation Committee's decision making with respect to named executive officers and director compensation matters, including providing advice on our executive pay philosophy, compensation peer group, incentive plan design and employment agreement design, providing competitive market studies, and informing the Compensation Committee about emerging best practices and changes in the regulatory and governance environment. Meridian provided information to the Compensation Committee regarding the compensation programs of ENLK and ENLC for 2017. Meridian's work for the Compensation Committee did not raise any conflicts of interest in 2017.

Role of Peer Group and Benchmarking

For 2017, the Compensation Committee and Meridian collaborated to identify the following companies as our peer companies: Boardwalk Pipeline Partners, L.P., Buckeye Partners, L.P., Enable Midstream Partners, LP, Enbridge Inc., Genesis Energy, L.P., HollyFrontier Corp., Magellan Midstream Partners, L.P., ONEOK Partners, L.P., Pembina Pipeline Corp., Plains All American Pipeline, L.P., Spectra Energy Corp., Sunoco Logistics Partners, L.P., Targa Resources Corp., and Western Gas Partners, L.P. (the "Peer Group"). We believe the Peer Group is representative of the industry in which we operate. The individual companies were chosen based on a number of factors, including each company's relative size/market capitalization, relative complexity of its business, similar organizational structure, competition for similar executive talent, and the roles and responsibilities of its named executive officers. The Compensation Committee considers the Peer Group companies annually, and historically there have been few changes from year to year. Companies are typically added or removed from the Peer Group as the result of a change in organizational structure or relative size/market capitalization as compared to us.

When evaluating annual compensation levels for each named executive officer, the Compensation Committee, with the assistance of Meridian, reviews compensation surveys and publicly available compensation data for executives in our Peer Group, including data on base salaries, annual bonuses, and long-term equity incentive awards. The Compensation Committee then uses that information to determine individual elements of compensation for the named executive officers in the context of their roles, levels of responsibility, accountability and decision-making authority within our organization and in the context of company size relative to the other Peer Group members. In addition, Meridian has provided guidance on current industry trends and best practices to the Compensation Committee relating to all aspects of executive compensation.

While compensation surveys and Peer Group data are considered, the Compensation Committee does not attempt to set compensation elements to meet specific benchmarks. Accordingly, other subjective factors are also considered in setting compensation elements, including, but not limited to, (i) effort and accomplishment on a group and individual basis, (ii) challenges faced and challenges overcome, (iii) unique skills, (iv) contribution to the management team, (v) succession planning and retention of our executive officers and (vi) the perception of both the Board and the Compensation Committee of our performance relative to expectations and actual market/business conditions.

Elements of Compensation

For fiscal year 2017, the principal elements of compensation for the named executive officers were the following:

- base salary;
- annual bonus awards;
- long-term incentive plan equity awards;
- retirement and health benefits; and
- severance and change of control benefits.

The Compensation Committee reviews and makes recommendations regarding the mix of compensation, both among short- and long-term compensation and cash and non-cash compensation, to establish structures that it believes are appropriate for each of the named executive officers. We believe that the mix of base salary, annual bonus awards, long-term incentive plan equity awards, retirement and health benefits, severance and change of control benefits and perquisites and other compensation fit our overall compensation objectives. We believe this mix of compensation provides opportunities to align and drive performance of our named executive officers in support of our strategic objectives and to attract, retain and motivate highly qualified talent with the skills and competencies that we require.

Base Salary. The Compensation Committee recommends base salaries for the named executive officers based on the historical salaries for services rendered to us and our affiliates, Peer Group data provided by Meridian, compensation surveys and performance and responsibilities of the named executive officers. The base salaries paid to our named executive officers for fiscal year 2017 (and payable for fiscal 2018) are as follows:

	Prior Salary	Base Salary Effective For 2018	Percent Increase (Decrease)
Michael J. Garberding (1)	$ 500,000	$ 650,000	30.0 %
Eric D. Batchelder (1)	$ —	$ 380,000	— %
Mac Hummel	$ 420,000	$ 435,000	3.6 %
Benjamin D. Lamb (2)	$ 345,000	$ 435,000	26.1 %
Barry E. Davis (1)	$ 695,000	$ 525,000	(24.5)%
Steve J. Hoppe (3)	$ 420,000	$ —	— %

(1) In January 2018, the Board appointed Mr. Davis to Executive Chairman of the Board, Mr. Garberding to President and Chief Executive Officer and Mr. Batchelder to Executive Vice President and Chief Financial Officer. Prior to January 2018, Mr. Davis served as Chief Executive Officer and Chairman of the Board, and Mr. Garberding served as President and Chief Financial Officer.

(2) In February 2018, the Board appointed Mr. Lamb to Executive Vice President, North Texas and Oklahoma. Prior to February 2018, Mr. Lamb served as Executive Vice President, Corporate Development.

(3) In January 2018, Mr. Hoppe resigned from his position as Executive Vice President and President of Gas Gathering, Processing and Transmission.

Bonus Awards. On March 3, 2017, the Board and the board of directors of the manager of ENLC (the "Manager Board") approved various modifications to our short-term incentive program (as modified, the "STI Program") based on recommendations from the Compensation Committee and the Governance and Compensation Committee of the Manager Board (the "Manager Committee"). The Board and the Manager Board (collectively, the "Boards") along with the Compensation Committee and the Manager Committee (collectively, the "EnLink Compensation Committees") oversee the STI Program. All employees, including named executive officers, are eligible to receive annual bonuses under the STI Program. Bonuses awarded to employees and named executive officers under the STI Program are based on the achievement of certain metrics established to measure our success and are subject to the discretion of the Boards and the EnLink Compensation Committees.

The metrics employed by the STI Program contemplate that bonuses may be earned based primarily upon the achievement of certain core goals (collectively, the "Primary Bonus Components"), which may change from year-to-year. As reflected in the table below, a separate weighting is applied for each of the Primary Bonus Components. The Primary Bonus Components for 2017 and associated information are as follows:

Component	Description	Weighting
Financial	Adjusted EBITDA and cost management to maximize financial performance	50% Adjusted EBITDA 10% Cost management
Growth	Timely and cost-effective growth pursuant to the Strategic Plan and overarching direction	10%
Operational	Efficient use of systems, assets and equipment for meeting contractual obligations, driving customer service and maximizing cash flow	10%
People	Train and develop our workforce	10%
Environmental, Health, & Safety	Prevent safety incidents and improve safety compliance, operations, and training	10%

Each year, performance under the Primary Bonus Components will be measured, as applicable, on an interpolated "threshold/target/maximum" or "does-not-meet/meets/exceeds" basis. Each year, a range of bonus pool values for the STI Program will be established to account for various levels of performance under the Primary Bonus Components, as applied on a weighted average basis. These bonus pool values are a framework, and are subject to the application of the discretion of the Boards and the EnLink Compensation Committees, to determine the bonus amounts that are ultimately payable under the STI Program, including to our named executive officers, as further described below.

The EnLink Compensation Committees and the Boards, with input from management, set the annual weightings for each Primary Bonus Component and any additional weightings that apply with respect to the features comprising a particular Primary Bonus Component. In addition, the EnLink Compensation Committees and the Boards, with input from management, set, as applicable, the “threshold/target/maximum” and the “does-not-meet/meets/exceeds” standards that apply to the Primary Bonus Components. These standards are based on a number of considerations, including, but not limited to, reasonable market expectations, internal company forecasts, available growth opportunities, company performance, leading indicators and industry standards.

The Boards, based on recommendations of the EnLink Compensation Committees, initially establish the target bonus awards that may be earned and ultimately determine the final bonus amounts, if any, that are payable under the STI Program for our named executive officers. Initial bonus award amounts for consideration by the EnLink Compensation Committees and the Boards for the named executive officers will be established by multiplying (x) the relevant named executive officer’s target bonus percentage by (y) the relevant named executive officer’s base salary (subject to certain adjustments to account for, among other things, mid-year changes in base salary or a mid-year hiring or termination) by (z) an achievement percentage for the relevant year.

The EnLink Compensation Committees believe that a portion of executive compensation for named executive officers must remain discretionary.Therefore, the STI Program contemplates that the EnLink Compensation Committees and the Boards retain discretion with respect to target bonus awards and the final bonus amounts for named executive officers. In this regard, the EnLink Compensation Committees may exercise such discretion to recommend to the Boards a reduction or increase of the target bonus or the final bonus amounts for a particular named executive officer to reward or address extraordinary individual performance, challenges and opportunities not reasonably foreseeable at the beginning of a performance period, internal equities, and external competition or opportunities.

The final amount of bonus for each named executive officer was approved by the Boards based upon theEnLink Compensation Committees’ recommendation and assessment of whether such officer met his or her performance objectives established at the beginning of the performance period. These performance objectives included the quality of leadership within the named executive officer’s assigned area of responsibility, the achievement of technical and professional proficiencies by the named executive officer, the execution of identified priority objectives by the named executive officer and the named executive officer’s contribution to, and enhancement of, the desired company culture. These performance objectives were reviewed and evaluated by the EnLink Compensation Committees as a whole. All named executive officers met or exceeded their minimum personal performance objectives for 2017. Accordingly, the EnLink Compensation Committees and the Boards awarded bonuses to the named executive officers as follows:

	Target Bonus Percentage (as a % of Base Salary)	**2017 Bonus (as a % of Base Salary)**	**2017 Bonus Amount**
Michael J. Garberding	90 %	100 %	$ 500,000
Mac Hummel	90 %	99 %	$ 415,000
Benjamin D. Lamb	90 %	100 %	$ 345,000
Barry E. Davis	125 %	138 %	$ 960,000
Steve J. Hoppe (1)	90 %	— %	$ —

(1) In January 2018, Mr. Hoppe resigned from his position as Executive Vice President and President of Gas Gathering, Processing and Transmission.

Target adjusted EBITDA was based upon a standard of reasonable market expectations and our performance and varies from year to year. For2017, our adjusted EBITDA levels for bonuses were $818.0 million for minimum threshold bonuses, $875.0 million for target bonuses and $945.0 million for maximum bonuses. For 2017, the STI Program provided for named executive officers to receive bonus payouts of 45% to 62.5% of base salary at the minimum threshold, 90% to 125% of base salary at the target level and 180% to 250% of base salary at the maximum level.

Long-Term Incentive Plans. Our named executive officers and outside directors are eligible to participate in the EnLink Midstream GP, LLC Long-Term Incentive Plan (the “GP Plan”) and the EnLink Midstream, LLC 2014 Long-Term Incentive Plan (the “2014 Plan”). Finally, certain directors, officers and employees participate, to the extent consistent with terms and agreed in connection with the Business Combination, in the EnLink Midstream, LLC 2009 Long-Term Incentive Plan (the "2009 Plan").

The Board, upon the recommendation of the Compensation Committee, approves the grants of equity awards to our named executive officers. The Compensation Committee believes that equity awards should comprise a significant portion of a named executive officer's total compensation and considers a number of factors when determining the grants to each individual named executive officer. The factors considered include: the general goal of allowing the named executive officer the opportunity to earn aggregate equity compensation (comprised of ENLK and ENLC units) targeted at the 75th percentile of our Peer Group; the amount of unvested equity held by the individual named executive officer; the named executive officer's performance; and other factors as determined by the Compensation Committee.

A discussion of each plan follows:

EnLink Midstream GP, LLC Long-Term Incentive Plan. EnLink Midstream GP, LLC has adopted the GP Plan for employees, consultants and independent contractors of EnLink Midstream GP, LLC and its affiliates and outside directors of our Board who perform services for us. The GP Plan is administered by the Compensation Committee and permits the grant of awards, which may be awarded in the form of restricted incentive units or options. On May 9, 2013, our unitholders approved the amendment and restatement of the GP Plan, which increased the number of common units representing limited partner interests in us authorized for issuance under the GP Plan by 3,470,000 common units to an aggregate of 9,070,000 common units and made certain other technical amendments. Effective April 6, 2016, our unitholders approved the amendment and restatement of the GP Plan, which increased the number of common units representing limited partner interests in us authorized for issuance under the GP Plan by 5,000,000 common units to an aggregate of 14,070,000 common units and other technical changes. Common units subject to an award under the GP Plan that are forfeited or are otherwise terminated or canceled will again become available for delivery pursuant to other awards under the GP Plan. Of the 14,070,000 common units that may be awarded under the GP Plan, 5,011,723 common units remain eligible for future grants as of December 31, 2017. The long-term compensation structure of the GP Plan is intended to align the performance of participants with long-term performance for our unitholders.

The GP Plan will automatically expire on March 3, 2026. The Board, in its discretion, may terminate or amend the GP Plan at any time with respect to any units for which a grant has not yet been made. The Board or the Compensation Committee also has the right to alter or amend the GP Plan or any part of the GP Plan from time to time, including increasing the number of units that may be granted subject to the approval requirements of the exchange upon which the common units are listed at that time. The Compensation Committee may generally amend the terms of any outstanding award under the GP Plan at any time. However, no action may be taken by the Board or the Compensation Committee under the GP Plan that would materially reduce the benefits of a participant under a previously granted award without the participant's consent.

The following forms of awards may be awarded under the GP Plan:

- *Options.* The GP Plan permits the grant of options covering common units. These options are rights to purchase a specified number of our common units at a specified price. The exercise price of an option cannot be less than the fair market value per common unit on the date on which the option is granted and the term of the option cannot exceed ten years from the date of grant. Options granted will become exercisable on such terms as the Compensation Committee determines. Under no circumstances will distributions or DERs (as defined below) be granted or made with respect to option awards. In addition, the options may, pursuant to their terms, become exercisable upon a change of control of us or our general partner as discussed below under "-Potential Payments Upon a Change of Control." Common units to be delivered upon the exercise of an option may be common units acquired by our general partner in the open market, common units already owned by our general partner, common units acquired by our general partner directly from us or any other person, or any combination of the foregoing. Our general partner will be entitled to reimbursement by us for the difference between the cost incurred by it in acquiring these common units and the proceeds received by it from an optionee at the time of exercise. Thus, the cost of the options will be borne by us. If we issue new common units upon exercise of the options our general partner will pay us the proceeds it received from the optionee upon exercise of the option.

- *Restricted Incentive Units.* The GP Plan permits the grant of restricted incentive units. These awards of restricted incentive units are rights that entitle the grantee to receive cash, common units or a combination of cash and common units of ENLK upon the vesting of such restricted incentive units. The Compensation Committee will determine the terms, conditions and limitations applicable to any awards of restricted incentive units. Awards of restricted incentive units will have a vesting period established in the sole discretion of the Compensation Committee, which may include, without limitation, vesting upon the achievement of specified performance goals. In addition, the restricted incentive units may, pursuant to their terms, vest upon a change of control of us or our general partner, as discussed below under "-Potential Payments Upon a Change of Control." Common units to be delivered upon the vesting of restricted incentive units may be common units acquired by our general partner in the open market, common units already owned by our general partner, common units acquired by our general partner directly from us or any other person or any combination of the foregoing. Our general partner will be entitled to reimbursement by us for the cost incurred in acquiring common units. The Compensation Committee, in its discretion, may grant tandem distribution equivalent rights ("DERs") with respect to restricted incentive units, which entitles a participant to receive cash or additional awards equal to the amount of any cash distributions made by us with respect to a common unit during the period the DER is outstanding. The Compensation Committee may provide, in its discretion, that the DERs will be subject to the same forfeiture and other restrictions as a restricted incentive unit and, if so restricted, such distributions will be held, without interest, until the restricted incentive unit vests or is forfeited with the distribution being paid or forfeited at the same time, as the case may be. We intend for the issuance of the common units upon vesting of the restricted incentive units under the GP Plan to serve as a means of incentive compensation for performance and not primarily as an opportunity to participate in the equity appreciation of the common units. Therefore, under the current policy, GP Plan participants will not pay any consideration for the common units they receive, and we will receive no remuneration for the units.

EnLink Midstream, LLC Long-Term Incentive Plans

2014 Plan. Employees, non-employee directors and other individuals who provide services to us or our affiliates may be eligible to receive awards under the 2014 Plan; however, the Manager Committee determines which eligible individuals receive awards under the 2014 Plan, subject to the Manager Board's approval of awards to our named executive officers. The 2014 Plan is administered by the Manager Committee and permits the grant of cash and equity-based awards, which may be awarded in the form of options, restricted unit awards, restricted incentive units, unit appreciation rights ("UARs"), DERs, unit awards, cash awards and performance awards. At the time of adoption of the 2014 Plan, 11,000,000 common units representing limited liability company interests in ENLC were initially reserved for issuance pursuant to awards under the 2014 Plan. Common units subject to an award under the 2014 Plan that are canceled, forfeited, exchanged, settled in cash or otherwise terminated, including withheld to satisfy exercise prices or tax withholding obligations, will again become available for delivery pursuant to other awards under the 2014 Plan. Of the 11,000,000 common units that may be awarded under the 2014 Plan, 7,864,403 common units remain eligible for future grants as ofDecember 31, 2017. The long-term compensation structure of the 2014 Plan is intended to align the performance of participants with long-term performance for ENLC's unitholders.

The 2014 Plan will automatically expire on February 5, 2024. The Manager Board may amend or terminate the 2014 Plan at any time, subject to any requirement of unitholder approval required by applicable law, rule or regulation. The Manager Committee may generally amend the terms of any outstanding award under the 2014 Plan at any time. However, no action may be taken by the Manager Board or the Manager Committee under the 2014 Plan that would materially and adversely affect the rights of a participant under a previously granted award without the participant's consent.

The following forms of awards may be awarded under the 2014 Plan:

- *Options.* The 2014 Plan permits the grant of options covering common units. These options are rights to purchase a specified number of common units of ENLC at a specified price. The exercise price of an option cannot be less than the fair market value per common unit on the date on which the option is granted and the term of the option cannot exceed ten years from the date of grant. Options granted will become exercisable on such terms as the Manager Committee determines. The Manager Committee will also determine the time or times at which, and the circumstances under which, an option may be exercised in whole or in part (including based on achievement of performance goals and/or future service requirements), the method of exercise, form of consideration payable in settlement, method by or forms in which common units will be delivered to participants, and whether or not an option will be in tandem with a UAR award. Under no circumstances will distributions or DERs be granted or made with respect to option awards. An option granted to an employee may consist of an option that complies with the requirements of Section 422 of the Internal Revenue Code (the "IRC"), referred to in the 2014 Plan as an "incentive unit option." In the case of an incentive unit option granted to an employee who owns (or is deemed to own) more than 10% of the total combined voting power of all classes of units, the exercise price of the option must be at least 110% of the fair market value per common unit on the date of grant and the term of the option cannot exceed five years from the date of grant.

- *Unit Appreciation Rights or UARs.* The 2014 Plan permits the grant of UARs. A UAR is a right to receive an amount equal to the excess of the fair market value of one common unit of ENLC on the date of exercise over the grant price of the UAR. UARs will be exercisable on such terms as theManager Committee determines. The Manager Committee will also determine the time or times at which and the circumstances under which a UAR may be exercised in whole or in part (including based on achievement of performance goals and/or future service requirements), the method of exercise, method of settlement, form of consideration payable in settlement, method by or forms in which common units will be delivered or deemed to be delivered to participants, whether or not a UAR shall be in tandem with an option award, and any other terms and conditions of any UAR. UARs may be either freestanding or in tandem with other awards. Under no circumstances will distributions or DERs be granted or made with respect to UAR awards.

- *Restricted Units.* The 2014 Plan permits the grant of restricted units. A restricted unit is a grant of a common unit of ENLC subject to a substantial risk of forfeiture, restrictions on transferability and any other restrictions determined by the Manager Committee. The Manager Committee may provide, in its discretion, that the distributions made by ENLC with respect to the restricted units will be subject to the same forfeiture and other restrictions as the restricted unit and, if so restricted, such distributions will be held, without interest, until the restricted unit vests or is forfeited with the unit distribution right being paid or forfeited at the same time, as the case may be. In addition, the Manager Committee may provide that such distributions be used to acquire additional restricted units for the participant. Under no circumstances will DERs be granted or made with respect to restricted unit awards.

- *Restricted Incentive Units.* The 2014 Plan permits the grant of restricted incentive units. These awards of restricted incentive units are rights that entitle the grantee to receive cash, common units of ENLC or a combination of cash and common units of ENLC upon the vesting of such restricted incentive units. Restricted incentive units may be subject to restrictions, including a risk of forfeiture, as determined by the Manager Committee. The Manager Committee may, in its sole discretion, grant DERs with respect to restricted incentive units. We intend for the issuance of the common units upon vesting of the restricted incentive units under the 2014 Plan to serve as a means of incentive compensation for performance and not primarily as an opportunity to participate in the equity appreciation of the common units. Therefore, under the current policy, 2014 Plan participants will not pay any consideration for the common units they receive, and ENLC will receive no remuneration for the units.

- *Distribution Equivalent Rights or DERs.* The 2014 Plan permits the grant of DERs. DERs entitle a participant to receive cash or additional awards equal to the amount of any cash distributions made with respect to an ENLC common unit during the period the right is outstanding. DERs may be granted as a stand-alone award or with respect to awards other than restricted units, options or UARs. Subject to Section 409A of the IRC, payment of a DER issued in connection with another award may be subject to the same vesting terms as the award to which it relates or different vesting terms, in the discretion of the Manager Committee.

- *Unit Awards.* The 2014 Plan permits the grant of unit awards, which are common units of ENLC that are not subject to vesting restrictions.

- *Cash Awards.* The 2014 Plan permits the grant of cash awards, which are awards denominated and payable in cash.

- *Performance Awards.* The 2014 Plan permits the grant of performance awards. Performance awards represent a participant's right to receive an amount of cash, common units of ENLC, or a combination of both, contingent upon the annual attainment of specified performance measures within a specified period. The Manager Committee or other committee that is intended to satisfy certain requirements of Section 162(m) of the IRC (the "Section 162(m) Committee"), as applicable, will determine the applicable performance period, the performance goals and such other conditions that apply to each performance award. In addition, the 2014 Plan permits, but does not require, the Manager Committee or the Section 162(m) Committee, as applicable, to structure any performance award made to a covered employee as qualified performance-based compensation under Section 162(m) of the IRC. As a result of tax reform that became effective on January 1, 2018, future grants of performance awards will no longer be eligible to qualify as qualified performance-based compensation under Section 162(m) of the IRC. However, it may be possible for performance awards that were outstanding as of November 2, 2017 to continue to qualify as qualified performance-based compensation for such purposes; so long as the awards are not modified in any material respect after such date (and assuming that the awards otherwise satisfy any additional transition relief guidance issued by the Internal Revenue Service). Section 162(m) of the IRC generally limits the deductibility for federal income tax purposes of annual compensation paid to certain top executives of a company to $1 million per covered employee in a taxable year (except to the extent such compensation qualifies as (among other things) qualified performance-based compensation as of November 2, 2017 (and are not materially modified), for purposes of Section 162(m) of the IRC). Prior to the payment of any compensation based on the achievement of performance goals applicable to performance awards that were outstanding as of November 2, 2017 and intended to provide qualified performance-based compensation under

Section 162(m) of the IRC, the Manager Committee or the Section 162(m) Committee, as applicable, must certify in writing that applicable performance goals and any of the material terms thereof were, in fact, satisfied.

Upon a change of control of us, our general partner or ENLC and except as provided in the applicable award agreement, the Manager Committee may cause options and UAR grants to be vested, may cause change of control consideration to be paid in respect of some or all of such awards, or may make other adjustments (if any) that it deems appropriate with respect to such awards. With respect to other awards, upon a change of control of ENLC and except as provided in the award agreement, the Manager Committee may cause such awards to be adjusted, which adjustments may relate to the vesting, settlement or the other terms of such awards.

EnLink Midstream 2009 Long-Term Incentive Plan. The EnLink Midstream, LLC 2009 Long-Term Incentive Plan (the "2009 Plan") Plan provides for the award of options, restricted units, restricted incentive units and other awards (collectively, "Awards"). As a result of the consummation of the Business Combination, however, it is anticipated that no future Awards will be granted under the 2009 Plan. The Manager Committee administers the 2009 Plan and has the authority to grant waivers of the applicable plan terms, conditions, restrictions and limitations. As of December 31, 2017, no common units are reserved for issuance under the 2009 Plan. Only unexercised options are outstanding under the 2009 Plan.

The Manager Committee may amend, modify, suspend or terminate the 2009 Plan, except that no amendment that would impair the rights of any participant to any Award may be made without the consent of such participant, and no amendment requiring unitholder approval under any applicable legal requirements will be effective until such approval has been obtained.

Performance Unit Awards. Beginning in 2015, our general partner and the managing member of ENLC granted performance awards under the GP Plan and the 2014 Plan, respectively. The performance award agreements provide that the vesting of restricted incentive units granted under the GP Plan and 2014 Plan is dependent on the achievement of certain total shareholder return ("TSR") performance goals relative to the TSR achievement of a peer group of companies (the "Peer Companies") over the applicable performance period. The performance award agreements contemplate that the Peer Companies for an individual performance award (the "Subject Award") are the companies comprising the Alerian MLP Index for Master Limited Partnerships ("AMZ"), excluding ENLK and ENLC, on the grant date for the Subject Award. The performance units will vest based on the percentile ranking of the average of our and ENLC's TSR achievement ("EnLink TSR") for the applicable performance period relative to the TSR achievement of the Peer Companies.

At the end of the vesting period, recipients receive distribution equivalents, if any, with respect to the number of performance units vested. The vesting of units ranges from 0% to 200% of the units granted depending on the EnLink TSR as compared to the Peer Companies on the vesting date. The fair value of each performance unit is estimated as of the date of grant using a Monte Carlo simulation with the following assumptions used for all performance unit grants made under the plan: (i) a risk-free interest rate based on United States Treasury rates as of the grant date; (ii) a volatility assumption based on the historical realized price volatility of our common units and the designated Peer Companies securities; (iii) an estimated ranking of us among the designated Peer Companies and (iv) the distribution yield. The fair value of the unit on the date of grant is expensed over a vesting period of approximately three years.

The total value of the equity compensation granted to our executive officers generally has been awarded 50% in ENLK restricted incentive units and 50% in restricted incentive units of ENLC for fiscal year 2017. In addition, our executive officers may receive additional grants of equity compensation in certain circumstances, such as promotions. For fiscal year 2017, our general partner granted 48,544, 35,060, 32,362, 102,482 and 35,060 performance and restricted incentive units to Messrs. Garberding, Hummel, Lamb, Davis and Hoppe, respectively. In addition, for fiscal year 2017, the managing member of ENLC granted 45,226, 32,664, 30,150, 95,478 and 32,664 performance and restricted incentive units to Messrs. Garberding, Hummel, Lamb, Davis and Hoppe, respectively. All performance and restricted incentive units that we grant are charged against earnings according to ASC 718.

Retirement and Health Benefits. All eligible employees are offered a variety of health and welfare and retirement programs. The named executive officers are generally eligible for the same programs on the same basis as other employees. We maintain a tax-qualified 401(k) retirement plan that provides eligible employees with an opportunity to save for retirement on a tax deferred basis. In 2017, we matched 100% of every dollar contributed for contributions of up to 6% of salary made by eligible participants plus a 2% non-discretionary contribution (not to exceed the maximum amount permitted by law). The retirement benefits provided to the named executive officers were allocated to us as general and administration expenses.

Perquisites. We generally do not pay for perquisites for any of the named executive officers, other than payment of dues, sales tax and related expenses for membership in an industry-related private lunch club (totaling less than $2,500 per year per named executive officer).

Change in Control and Severance Agreements

All of our named executive officers and certain members of senior management have entered into amended change in control agreements (the "Change in Control Agreements") with the Operating Partnership and amended severance agreements (the "Severance Agreements" and collectively with the Change in Control Agreements, the "Agreements") with the Operating Partnership. Additionally, as certain individuals become members of senior management, the individual may become a party to a change in control agreement and/or a severance agreement in substantially the same form as the applicable Agreement.

The Agreements restrict the officers from competing with us, as well as the Operating Partnership, ENLC, its manager, our general partner and their respective affiliates and subsidiaries (the "Company Group") during the term of employment. The Agreements also restrict the officers from disclosing confidential information of the Company Group and disparaging any member of the Company Group, in each case, during or after the term of their employment. In addition, the Agreements restrict the officers, both during their employment and for varying periods following the termination of employment, from (i) soliciting other employees to terminate their employment with any member of the Company Group or accept employment with a third party and (ii) diverting the business of a client or customer of any member of the Company Group or attempting to convert a client or customer of any member of the Company Group. The Agreements provide the Operating Partnership with equitable remedies and with the right to clawback benefits if the restrictions described in this paragraph are breached by the officer. In the event of a termination, the terminated employee is required to execute a general release of the Company Group in order to receive any benefits under the Agreements.

Under the Severance Agreements, if an officer's employment is terminated without cause (as defined in the Severance Agreement) or is terminated by the officer for good reason (as defined in the Severance Agreement), such officer will be entitled to receive (i) his or her accrued base salary up to the date of termination, (ii) any unpaid annual bonus with respect to the calendar year ending prior to the officer's termination date that has been earned as of such date, (iii) a prorated amount of the bonus (to the extent such bonus would have otherwise been earned by such officer) for the calendar year in which the termination occurs, (iv) such other fringe benefits (other than any bonus, severance pay benefit or medical insurance benefit) normally provided to employees that are already earned or accrued as of the date of termination (the foregoing items in clauses (i) - (iv) are referred to as the "General Benefits"), (v) certain outplacement services (the "Outplacement Benefits"), (vi) a lump sum severance equal to the sum of (A) the officer's then-current base salary and (B) any target bonus (as defined in the applicable Agreement) for the year that includes the date of termination (the "Severance Benefit") times two for the officer (other members of senior management are each entitled to one times the Severance Benefit), plus (vii) an amount equal to the cost to the officer to extend his or her then-current medical insurance benefits for 18 months following the effective date of the termination (the "Medical Severance Benefit").

Potential Payments Upon a Change of Control

Under the Change in Control Agreements, if, within a period that begins 120 days prior to and ends 24 months following a change in control (as defined in the Change in Control Agreement), an officer's employment is terminated without cause (as defined in the Change in Control Agreement) or is terminated by the officer for good reason (as defined in the Change in Control Agreement), such officer will be entitled to the General Benefits, the Outplacement Benefits, the Medical Severance Benefit and the Severance Benefit; provided, however, that the Chief Executive Officer ("CEO") would be entitled to three times the Severance Benefit, and the other officers would be entitled to two times the Severance Benefit. Other members of senior management do not receive an increase in the Severance Benefit if they are terminated in connection with a change in control.

In addition, the Agreements provide for the General Benefits upon the officer's termination of employment due to his or her death or disability (as defined in the Agreements).

The Agreements provide that an officer may only become entitled to payments under the Severance Agreement or the Change in Control Agreement, but not under both Agreements. Upon execution of a Severance Agreement, the Severance Agreement will continue in effect until (i) the first anniversary of the execution date; provided that the term will be automatically renewed for additional one-year periods beginning on the day following the first anniversary of the execution date (each, a "Renewal Date"), unless the Board or Compensation Committee, as applicable, provides the officer with written notice (a "Non-Renewal Notice") of the Operating Partnership's election not to renew the term at least 30 days prior to any

Renewal Date or (ii) the termination of the officer's employment; provided that an officer's employment may not be terminated by the Operating Partnership for any reason other than cause (as defined in the Severance Agreement) for the 90-day period that follows the termination of the Severance Agreement pursuant to a Non-Renewal Notice. Upon execution of a Change in Control Agreement, the Change in Control Agreement will continue in effect until (i) the applicable Renewal Date and be automatically renewed for additional one-year periods unless the Board or Compensation Committee, as applicable, provides the officer with a Non-Renewal Notice at least 90 days prior to any Renewal Date or (ii) the termination of the officer's employment, except that a Change in Control Agreement may not be terminated for a period that begins 120 days prior to, and ends 24 months following, a change in control.

If the payments and benefits provided to an officer under the Agreements (i) constitute a "parachute payment" as defined in Section 280G of the IRC and exceed three times the officer's "base amount" as defined under Section 280G(b)(3) of the IRC, and (ii) would be subject to the excise tax imposed by Section 4999 of the IRC, then the officer's payments and benefits will be either (A) paid in full, or (B) reduced and payable only as to the maximum amount that would result in no portion of the payments and benefits being subject to such excise tax, whichever results in the receipt by the officer on an after-tax basis of the greatest amount (taking into account the applicable federal, state and local income taxes, the excise tax imposed by Section 4999 of the IRC and all other taxes, including any interest and penalties, payable by the officer).

With respect to the long-term incentive plans, the amounts to be received by our named executive officers in the event of a change of control (as defined in the long-term incentive plans) will be automatically determined based on the number of units underlying any unvested equity incentive awards held by a named executive officer at the time of a change of control. The terms of the long-term incentive plans were determined based on past practice and the applicable compensation committee's understanding of similar plans utilized by public companies generally at the time we adopted such plans. The determination of the reasonable consequences of a change of control is periodically reviewed by the applicable compensation committee.

Upon a change of control, and except as provided in the award agreement, the applicable compensation committee may cause options and UAR grants to be vested, may cause change of control consideration to be paid in respect of some or all of such awards, or may make other adjustments (if any) that it deems appropriate with respect to such awards. With respect to other awards, upon a change of control and except as provided in the award agreement, the applicable compensation committee may cause such awards to be adjusted, which adjustments may relate to the vesting, settlement or the other terms of such awards.

The potential payments that may be made to the named executive officers upon a termination of their employment or in connection with a change of control as of December 31, 2017 are set forth in the table in the section below entitled "Payments Upon Termination or Change in Control."

Role of Executive Officers in Executive Compensation

The Board, upon recommendation of the Compensation Committee, determines the compensation payable to each of the named executive officers. None of the named executive officers serves as a member of the Compensation Committee. The CEO makes recommendations regarding the compensation of his leadership team with the Compensation Committee, including specific recommendations for each element of compensation for each of the named executive officers. The CEO does not make any recommendations regarding his personal compensation.

Tax Considerations

We have structured the compensation program in a manner intended to be exempt from, or to comply with Section 409A of the IRC. If an executive is entitled to nonqualified deferred compensation benefits that are subject to Section 409A, and such benefits do not comply with Section 409A of the IRC, then the benefits are taxable in the first year they are not subject to a substantial risk of forfeiture. In such case, the service provider is subject to regular federal income tax, interest and an additional federal excise tax of 20% of the benefit includible in income.

Summary Compensation Table

The following table sets forth certain compensation information for our named executive officers.

Name and Principal Position	Year	Salary ($)	Bonus ($)(1)	Restricted Incentive Unit, and Performance Unit Awards ($)(2)	All Other Compensation ($)	Total ($)
Michael J. Garberding	2017	500,000	500,000	2,147,374	396,190 (4)	3,543,564
President and Chief Executive Officer (3)	2016	462,885	416,000	3,409,650	376,304	4,664,839
	2015	449,423	400,000	1,963,183	281,294	3,093,900
Mac Hummel	2017	415,192	415,000	1,550,909	322,421 (5)	2,703,522
Executive Vice President and President of NGL and Crude	2016	390,000	225,000	1,092,502	317,871	2,025,373
	2015	389,538	300,000	1,570,488	203,570	2,463,596
Benjamin D. Lamb	2017	345,000	345,000	1,431,552	274,563 (6)	2,396,115
Executive Vice President, North Texas and Oklahoma (7)	2016	318,558	250,000	2,181,257	212,310	2,962,125
	2015	283,904	225,000	1,702,321	92,414	2,303,639
Barry E. Davis	2017	695,000	960,000	4,533,371	565,075 (8)	6,753,446
Executive Chairman of the Board (3)	2016	660,000	650,000	2,498,230	570,612	4,378,842
	2015	659,308	690,000	3,435,500	440,742	5,225,550
Steve J. Hoppe (9)	2017	420,000	—	1,550,909	250,097 (10)	2,221,006
	2016	390,000	280,000	1,092,502	261,800	2,024,302
	2015	389,827	300,000	1,570,488	147,699	2,408,014

(1) Bonuses include all annual bonus payments. For 2015, all annual bonus payments were paid in cash. For 2016 and 2017, the named executive officers received bonuses in the form of equity awards that immediately vest. The amounts shown for 2016 and 2017 represent the grant date fair value of awards computed in accordance with ASC 718. Such awards were allocated 50% in restricted incentive units of ENLK and 50% in restricted incentive units of ENLC.

(2) The amounts shown represent the grant date fair value of awards computed in accordance with ASC 718. See "Item 8. Financial Statements and Supplementary Data—Note 11" for the assumptions made in our valuation of such awards.

(3) In January 2018, the Board appointed Mr. Davis to Executive Chairman of the Board, Mr. Garberding to President and Chief Executive Officer and Mr. Batchelder to Executive Vice President and Chief Financial Officer. Prior to January 2018, Mr. Davis served as Chief Executive Officer and Chairman of the Board, and Mr. Garberding served as President and Chief Financial Officer.

(4) Amount of all other compensation for Mr. Garberding includes a matching 401(k) contribution of $13,769, a 401(k) non-discretionary contribution of $5,400, DERs with respect to restricted incentive units of ENLK in the amount of $236,339 and DERs with respect to restricted incentive units of ENLC in the amount of $140,682.

(5) Amount of all other compensation for Mr. Hummel includes a matching 401(k) contribution of $16,200, a 401(k) non-discretionary contribution of $5,400, $75,526 toward temporary housing expenses, DERs with respect to restricted incentive units of ENLK in the amount of $143,648, and DERs with respect to restricted incentive units of ENLC in the amount of $81,647.

(6) Amount of all other compensation for Mr. Lamb includes a matching 401(k) contribution of $16,200, a 401(k) non-discretionary contribution of $5,400, DERs with respect to restricted incentive units of ENLK in the amount of $159,514, DERs with respect to restricted incentive units of ENLC in the amount of $93,449.

(7) In February 2018, the Board appointed Mr. Lamb to Executive Vice President, North Texas and Oklahoma. Prior to February 2018, Mr. Lamb served as Executive Vice President, Corporate Development.

(8) Amount of all other compensation for Mr. Davis includes a matching 401(k) contribution of $16,200, a 401(k) non-discretionary contribution of $5,400, DERs with respect to restricted incentive units of ENLK in the amount of $344,886 and DERs with respect to restricted incentive units of ENLC in the amount of $198,589.

(9) In January 2018, Mr. Hoppe resigned from his position as Executive Vice President and President of Gas Gathering, Processing and Transmission.

(10) Amount of all other compensation for Mr. Hoppe includes a matching 401(k) contribution of $16,200, a 401(k) non-discretionary contribution of $5,400, DERs with respect to restricted incentive units of ENLK in the amount of $145,107 and DERs with respect to restricted incentive units of ENLC in the amount of $83,389.

CEO Pay Ratio

For fiscal year 2017, the annual total compensation for the then Chairman of our Board and CEO, Barry E. Davis, was $6.8 million and for the median employee was $111,319. The resulting ratio of annual total compensation of the CEO to the annual total compensation of our median employee was 61:1. This pay ratio is a reasonable estimate calculated in accordance with the requirements of Item 402(u) of Regulation S-K. As a result of our methodology for determining the pay ratio, which is described below, our pay ratio may not be comparable to the pay ratios of other companies in our industry or in other industries because other companies may rely on different methodologies or assumptions, or may make adjustments that we do not make.

To determine the pay ratio, we first identified a median employee by examining 2017 W-2 Box 1 Federal Taxable Wages (the "Taxable Wages Measure") for all of our employees, excluding the CEO, who were employed on December 29, 2017, the last business day of the 2017 fiscal year. We included all employees whether employed as full-time, part-time or on a seasonal basis, and compensation was annualized for any full-time employee that was not employed for all of fiscal year 2017. We use the Taxable Wages Measure because it is consistently applied for all employees and because we believe it reasonably reflects the annual compensation of our employees. After identifying the median employee, we calculated annual total compensation for the median employee using the same methodology used for calculating the annual total compensation of our named executive officers as set forth in the 2017 Summary Compensation Table above.

Grants of Plan-Based Awards for Fiscal Year 2017 Table

The following tables provide information concerning each grant of an award made to a named executive officer for fiscal year 2017, including, but not limited to, awards made under the GP Plan and the 2014 Plan.

ENLINK MIDSTREAM GP, LLC—GRANTS OF PLAN-BASED AWARDS

		Estimated Future Payouts Under Equity Incentive Plan Awards				
Name	**Grant Date**	**Threshold (#)**	**Target (#)(1)**	**Maximum (#)(1)**	**All Other Unit Awards: Number of Units (2)**	**Grant Date Fair Value of Unit Awards ($)(3)**
Michael J. Garberding	3/14/2017				24,272	438,110
	3/14/2017	—	24,272	48,544		624,519
Mac Hummel	3/14/2017				17,530	316,417
	3/14/2017	—	17,530	35,060		451,047
Benjamin D. Lamb	3/14/2017				16,181	292,067
	3/14/2017	—	16,181	32,362		416,337
Barry E. Davis	3/14/2017				51,241	924,900
	3/14/2017	—	51,241	102,482		1,318,431
Steve J. Hoppe (3)	3/14/2017				17,530	316,417
	3/14/2017	—	17,530	35,060		451,047

(1) These grants include accrued DERs that provide for distributions on performance awards, unless otherwise forfeited, if distributions are made on common units during the restriction period. When the performance awards vest on January 1, 2020, recipients receive DERs, if any, with respect to the number of performance awards vested.

(2) These grants include DERs that provide for distribution on restricted incentive units if made on unrestricted common units during the restriction period unless otherwise forfeited and vest 100% on January 1, 2020.

(3) The amounts shown represent the grant date fair value of awards computed in accordance with ASC 718. See "Item 8. Financial Statements and Supplementary Data—Note 11" for the assumptions made in our valuation of such awards.

(4) In January 2018, Mr. Hoppe resigned from his position as Executive Vice President and President of Gas Gathering, Processing and Transmission. Pursuant to his resignation, the restricted incentive units and performance awards granted during 2017 were forfeited.

ENLINK MIDSTREAM, LLC—GRANTS OF PLAN-BASED AWARDS

Name	Grant Date	Estimated Future Payouts Under Equity Incentive Plan Awards: Threshold (#)	Estimated Future Payouts Under Equity Incentive Plan Awards: Target (#)(1)	Estimated Future Payouts Under Equity Incentive Plan Awards: Maximum (#)(1)	All Other Unit Awards: Number of Units (2)	Grant Date Fair Value of Unit Awards ($)(3)
Michael J. Garberding	3/14/2017				22,613	$ 434,170
	3/14/2017	—	22,613	45,226		$ 650,576
Mac Hummel	3/14/2017				16,332	$ 313,574
	3/14/2017	—	16,332	32,664		$ 469,872
Benjamin D. Lamb	3/14/2017				15,075	$ 289,440
	3/14/2017	—	15,075	30,150		$ 433,708
Barry E. Davis	3/14/2017				47,739	$ 916,589
	3/14/2017	—	47,739	95,478		$ 1,373,451
Steve J. Hoppe (4)	3/14/2017				16,332	$ 313,574
	3/14/2017	—	16,332	32,664		$ 469,872

(1) These grants include accrued DERs that provide for distributions on performance awards, unless otherwise forfeited, if distributions are made on common units during the restriction period. When the performance awards vest on January 1, 2020, recipients receive DERs, if any, with respect to the number of performance awards vested.

(2) These grants include DERs that provide for distribution on restricted incentive units if made on unrestricted common units during the restriction period unless otherwise forfeited and vest 100% on January 1, 2020.

(3) The amounts shown represent the grant date fair value of awards computed in accordance with ASC 718. See "Item 8. Financial Statements and Supplementary Data—Note 11" for the assumptions made in our valuation of such awards.

(4) In January 2018, Mr. Hoppe resigned from his position as Executive Vice President and President of Gas Gathering, Processing and Transmission. Pursuant to his resignation, the restricted incentive units and performance awards granted during 2017 were forfeited.

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Outstanding Equity Awards at Fiscal Year-End Table for Fiscal Year2017

The following tables provide information concerning all outstanding equity awards made to a named executive officer as ofDecember 31, 2017, including, but not limited to, awards made under the GP Plan, 2014 Plan and 2009 Plan.

ENLINK MIDSTREAM GP, LLC—OUTSTANDING EQUITY AWARDS AT FISCAL YEAR-END

		Stock Awards			
Name	Vesting Year (1)	Number of Units That Have Not Vested (#)	Market Value of Shares or Units That Have Not Vested ($)(2)	Equity Incentive Plan Awards: Number of Unearned Units or Other Rights that Have Not Vested (#)(3)	Equity Incentive Plan Awards: Market or Payout Value of Unearned Units or Other Rights That Have Not Vested ($)
Michael J. Garberding	2020	45,411	697,967	45,411	697,967
	2019	82,712	1,271,283	33,784	519,260
	2018	17,532	269,467	17,532	269,467
Mac Hummel	2020	17,530	269,436	17,530	269,436
	2019	55,918	859,460	25,629	393,918
	2018	14,025	215,564	14,025	215,564
Benjamin D. Lamb	2020	30,273	465,296	30,273	465,296
	2019	53,588	823,648	16,309	250,669
	2018	16,553	254,420	11,695	179,752
Barry E. Davis	2020	51,241	787,574	51,241	787,574
	2019	128,145	1,969,589	58,248	895,272
	2018	30,680	471,552	30,680	471,552
Steve J. Hoppe (4)	2020	17,530	269,436	17,530	269,436
	2019	55,918	859,460	25,629	393,918
	2018	14,025	215,564	14,025	215,564

(1) Restricted incentive units vest on January 1st of the applicable year, with the exception of 4,858 restricted incentive units awarded to Mr. Lamb that vest on April 1, 2018.

(2) The closing price for the ENLK common units was $15.37 as of December 29, 2017.

(3) Reflects the target number of performance units granted to the named executive officers multiplied by a performance percentage of 100%. Vesting of these awards on January 1st of the applicable year is contingent upon EnLink TSR performance over the applicable performance period measured against a peer group of companies.

(4) In January 2018, Mr. Hoppe resigned from his position as Executive Vice President and President of Gas Gathering, Processing and Transmission.

ENLINK MIDSTREAM, LLC—OUTSTANDING EQUITY AWARDS AT FISCAL YEAR-END

		Unit Awards			
Name	Vesting Year (1)	Number of Units That Have Not Vested (#)	Market Value of Shares or Units That Have Not Vested ($)(2)	Equity Incentive Plan Awards: Number of Unearned Units or Other Rights that Have Not Vested (#)(3)	Equity Incentive Plan Awards: Market or Payout Value of Unearned Units or Other Rights That Have Not Vested ($)(2)
Michael J. Garberding	2020	46,051	810,498	46,051	810,498
	2019	71,457	1,257,643	29,187	513,691
	2018	15,823	278,485	15,823	278,485
Mac Hummel	2020	16,332	287,443	16,332	287,443
	2019	48,309	850,238	22,142	389,699
	2018	12,658	222,781	12,658	222,781
Benjamin D. Lamb	2020	30,700	540,320	30,700	540,320
	2019	46,296	814,810	14,090	247,984
	2018	13,630	239,888	10,074	177,302
Barry E. Davis	2020	47,739	840,206	47,739	840,206
	2019	110,709	1,948,478	50,322	885,667
	2018	27,690	487,344	27,690	487,344
Steve J. Hoppe (4)	2020	16,332	287,443	16,332	287,443
	2019	48,309	850,238	22,142	389,699
	2018	12,658	222,781	12,658	222,781

(1) Restricted incentive units vest on January 1st of the applicable year, with the exception of 3,556 restricted incentive units for Mr. Lamb that vest on April 1, 2018.

(2) The closing price for the ENLC common units was $17.60 as of December 29, 2017.

(3) Reflects the target number of performance units granted to the named executive officers multiplied by a performance percentage of 100%. Vesting of these awards on January 1st of the applicable year is contingent upon EnLink TSR performance over the applicable performance period measured against a peer group of companies.

(4) In January 2018, Mr. Hoppe resigned from his position as Executive Vice President and President of Gas Gathering, Processing and Transmission.

Units Vested Table for Fiscal Year 2017

The following table provides information related to the vesting of restricted units and restricted incentive units during fiscal year ended2017.

UNITS VESTED

	EnLink Midstream Partners, LP Unit Awards		EnLink Midstream, LLC Unit Awards	
Name	**Number of Units Acquired on Vesting**	**Value Realized on Vesting**	**Number of Units Acquired on Vesting**	**Value Realized on Vesting**
Michael J. Garberding	59,040	$ 1,142,942 (1)	52,107	$ 1,034,529 (6)
Mac Hummel	42,128	$ 815,763 (2)	33,338	$ 662,386 (7)
Benjamin D. Lamb	22,187	$ 409,565 (3)	19,277	$ 367,067 (8)
Barry E. Davis	113,097	$ 2,189,862 (4)	99,347	$ 1,974,152 (9)
Steve J. Hoppe	47,375	$ 917,284 (5)	41,640	$ 827,349 (10)

(1) Consisted of 11,391 units at $19.27 per unit and 47,649 units at $19.38 per unit.
(2) Consisted of 6,161 units at $19.27 per unit, 4,201 units at $19.38 per unit and 31,766 units at $19.38 per unit.
(3) Consisted of 6,846 units at $19.27 per unit, 7,147 units at $19.38 per unit and 8,194 units at $16.98 per unit.
(4) Consisted of 17,798 units at $19.27 per unit and 95,299 units at $19.38 per unit.
(5) Consisted of 7,667 units at $19.27 per unit and 39,708 units at $19.38 per unit.
(6) Consisted of 11,123 units at $19.50 per unit and 40,984 units at $19.95 per unit.
(7) Consisted of 6,016 units at $19.50 per unit and 27,322 units at $19.95 per unit.
(8) Consisted of 6,684 units at $19.50 per unit, 6,148 units at $19.95 per unit and 6,445 units at $17.70 per unit.
(9) Consisted of 17,380 units at $19.50 per unit and 81,967 units at $19.95 per unit.
(10) Consisted of 7,487 units at $19.50 per unit and 34,153 units at $19.95 per unit.

Payments Upon Termination or Change of Control

The following tables show potential payments that would have been made to the named executive officers as ofDecember 31, 2017.

Named Executive Officer	Payment Under Severance Agreements Upon Termination Other Than For Cause or With Good Reason ($)(1)	Health Care Benefits Under Change in Control and Severance Agreements Upon Termination Other Than For Cause or With Good Reason ($)(2)	Payment and Health Care Benefits Under Change in Control and Severance Agreements Upon Termination For Cause or Without Good Reason ($)(3)	Payment Under Change in Control Agreements Upon Termination and Change of Control ($)(4)	Acceleration of Vesting Under Long-Term Incentive Plans Upon Change of Control ($)(5)
Michael J. Garberding	2,450,000	31,220	—	2,450,000	3,725,411
Mac Hummel	2,061,000	31,220	—	2,061,000	2,223,378
Benjamin D. Lamb	1,706,000	33,556	—	1,706,000	2,439,081
Barry E. Davis	4,137,500	34,095	—	5,701,250	10,872,358
Steve J. Hoppe (6)	2,063,312	33,556	—	2,063,312	2,223,378

(1) Each named executive officer is entitled to a lump sum amount equal to two times the Severance Benefit, the Outplacement Benefit, and when applicable, the bonus amounts comprising the General Benefits will be paid if he is terminated without cause (as defined in the Severance Agreement) or if he terminates employment for good reason (as defined in the Severance Agreement), subject to compliance with certain non-competition and non-solicitation covenants described elsewhere in this Annual Report on Form 10-K. The figures shown do not include amounts of base salary previously paid or fringe benefits previously received.

(2) Each named executive officer is entitled to health care benefits equal to a lump sum payment of the estimated monthly cost of the benefits under COBRA for 18 months if he is terminated without cause (as defined in the applicable Severance Agreement or Change of Control Agreement (the “Applicable Agreement”) or if he terminates employment for good reason (as defined in the Applicable Agreement).

(3) Each named executive officer is entitled to his then current base salary up to the date of termination plus such other fringe benefits (other than any bonus, severance pay benefit, participation in the company’s 401(k) employee benefit plan, or medical insurance benefit) normally provided to employees of the company as earned up to the date of termination if he is terminated for cause (as defined in the Applicable Agreement) or he terminates employment without good reason (as defined in the Applicable Agreement). The figures shown do not include amounts of base salary previously paid or fringe benefits previously received.

(4) Each named executive officer is entitled to a lump sum payment equal to two times the Severance Benefit (three times in the case of the Chief Executive Officer), the Outplacement Benefit, and when applicable, the bonus amounts comprising the General Benefits will be paid if he is terminated without cause (as defined in the Change of Control Agreement) or if he terminates employment for good reason (as defined in the Change of Control Agreement) within one-hundred and twenty (120) days prior to or two (2) years following a change in control (as defined in the Severance Agreement), subject to compliance with certain non-competition, non-solicitation and other covenants described elsewhere in this Annual Report on Form 10-K. The figures shown do not include amounts of base salary previously paid or fringe benefits previously received.

(5) Each named executive officer is entitled to accelerated vesting of certain outstanding equity awards in the event of a change of control (as defined under the long-term incentive plans). These amounts correspond to the values set forth in the table in the section above entitled Outstanding Equity Awards at Fiscal Year-End Table for Fiscal Year 2017.

(6) In January 2018, Mr. Hoppe resigned from his position as Executive Vice President and President of Gas Gathering, Processing and Transmission.

Compensation of Directors for Fiscal Year 2017

DIRECTOR COMPENSATION

Name	Fees Earned or Paid in Cash ($)	Unit Awards ($) (1)	All Other Compensation ($)(2)	Total ($)
Leldon E. Echols	96,500	99,995	7,995	204,490
Scott A. Griffiths	97,500	100,001	9,632	207,133
Mary P. Ricciardello	90,000	99,995	7,995	197,990
Kyle D. Vann	115,000	100,001	9,632	224,633

(1) Mr. Echols, Mr. Griffiths, Ms. Ricciardello and Mr. Vann were granted awards of restricted incentive units of ENLK on March 7, 2017 with a fair market value of $19.38 per unit and that will vest on March 7, 2018 in the following amounts, respectively: 2,580, 5,160, 2,580 and 5,160. Mr. Echols and Ms. Ricciardello were granted awards of restricted incentive units of ENLC on March 7, 2017 with a fair market value of $19.95 per unit and that will vest on March 7, 2018 in the following amounts, respectively: 2,506 and 2,506. The amounts shown represent the grant date fair value of awards computed in accordance with ASC 718. See "Item 8. Financial Statements and Supplementary Data—Note 11" for the assumptions made in our valuation of such awards. At December 31, 2017, Mr. Echols, Mr. Griffiths, Ms. Ricciardello and Mr. Vann held aggregate outstanding restricted incentive unit awards of ENLK, in the following amounts, respectively: 2,580, 5,160, 2,580 and 5,160. At December 31, 2017, Mr. Echols and Ms. Ricciardello held aggregate outstanding restricted incentive units of ENLC in the following amounts, respectively: 2,506 and 2,506.

(2) Other Compensation is comprised of DERs with respect to restricted incentive units.

Each director of EnLink Midstream GP, LLC who is not an employee of EnLink Midstream GP, LLC is paid an annual retainer fee of $72,500 and equity compensation valued at $100,000. Directors do not receive an attendance fee for each regularly scheduled quarterly board meeting or each additional meeting that they attend. The respective chairs of each committee receive the following annual fees: Audit—$24,000, EnLink Compensation Committees—$10,000 and Conflicts—$20,000. The respective members of each committee receive the following annual fees: Audit—$17,500, EnLink Compensation Committees—$7,500 and Conflicts—$15,000. Directors are also reimbursed for related out-of-pocket expenses. Michael J. Garberding, Barry E. Davis, Kevin D. Lafferty, Lyndon Taylor, David A. Hager, Tony Vaughn, R. Alan Marcum and Jeffery L. Ritenour, as officers of the Managing Member or Devon, receive no separate compensation for their respective service as directors. For directors that serve on both the boards of EnLink Midstream GP, LLC and EnLink Midstream Manager, LLC, the above listed fees are generally allocated 75% to us and 25% to ENLC, except in the case for service on the Audit Committee, where the chair is paid a separate fee for each entity and meeting fees are split 50% to each entity.

Compensation Committee Interlocks and Insider Participation

During the fiscal year ended 2017, the Compensation Committee was composed of Scott A. Griffiths and David A. Hager. No member of the Compensation Committee during fiscal 2017 was a current or former officer or employee of EnLink Midstream GP, LLC or had any relationship requiring disclosure by us under Item 404 of Regulation S-K as adopted by the SEC. None of EnLink Midstream GP, LLC's executive officers served on the board of directors or the compensation committee of any other entity for which any officers of such other entity served either on the Board or the Compensation Committee.

The Compensation Committee of EnLink Midstream GP, LLC held six meetings during fiscal year 2017. Each member attended 100% of the meetings.

Board Leadership Structure and Risk Oversight

The Board has no policy that requires that the positions of the Chairman of the Board (the "Chairman") and the Chief Executive Officer be separate or that they be held by the same individual. The Board believes that this determination should be based on circumstances existing from time to time, including the composition, skills and experience of the Board and its members, specific challenges faced by us or the industry in which we operate, and governance efficiency. Based on these factors, the Board determined that having Barry E. Davis serve as the Chief Executive Officer and Chairman up to January 2018 was in our best interest, and that such arrangement made the best use of Mr. Davis' unique skills and experience in the industry. In January 2018, the Board appointed Mr. Davis to Executive Chairman of the Board and Mr. Garberding to President and Chief Executive Officer, thereby separating the positions of Chairman and Chief Executive Officer.

The Board is responsible for risk oversight. Management has implemented internal processes to identify and evaluate the risks inherent in our business and to assess the mitigation of those risks. The Audit Committee will review the risk assessments with management and provide reports to the Board regarding the internal risk assessment processes, the risks identified and the mitigation strategies planned or in place to address the risks in the business. The Board and the Audit Committee each provide insight into the issues, based on the experience of their members, and provide constructive challenges to management's assumptions and assertions.

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

EnLink Midstream Partners, LP Ownership

The following table shows the beneficial ownership of units of EnLink Midstream Partners, LP as of February 14, 2018, held by:

- each person who beneficially owns 5% or more of any class of units then outstanding;
- all the directors of EnLink Midstream GP, LLC;
- each named executive officer of EnLink Midstream GP, LLC; and
- all the directors and executive officers of EnLink Midstream GP, LLC as a group.

The percentage of total units beneficially owned is based upon a total of350,043,269 common units (including20,338 restricted incentive units that are deemed beneficially owned) and 57,469,939 Series B Preferred Units as of February 14, 2018. Series C Preferred Units are perpetual preferred units that are not convertible into common units and therefore are not factored into the percentage ownership calculations. None of the named beneficial owners set forth in the table below owns any of the 400,000 outstanding Series C Preferred Units as of February 14, 2018.

Name of Beneficial Owner (1)	Common Units Beneficially Owned	Percentage of Common Units Beneficially Owned (2)	Series B Preferred Units Beneficially Owned	Percentage of Series B Preferred Units Beneficially Owned	Total Units Beneficially Owned	Percentage of Total Units Beneficially Owned (3)
Devon Energy Corporation (4)	183,189,051	52.33%	—	—%	183,189,051	44.95%
Enfield Holdings, L.P. (5)	—	*	57,469,939	100 %	57,469,939	14.10%
Michael J. Garberding	157,645	*	—	—%	157,645	*
Eric D. Batchelder	—	*	—	—%	—	*
Mac Hummel	51,639	*	—	—%	51,639	*
Benjamin D. Lamb (6)	42,857	*	—	—%	42,857	*
Barry E. Davis (7)	497,478	*	—	—%	497,478	*
Leldon E. Echols (8)	31,697	*	—	—%	31,697	*
David A. Hager	—	*	—	—%	—	*
Mary P. Ricciardello (9)	10,573	*	—	—%	10,573	*
Scott A. Griffiths (10)	21,148	*	—	—%	21,148	*
Kyle D. Vann (11)	65,393	*	—	—%	65,393	*
Christopher Ortega	—	*	—	—%	—	*
Jeff L. Ritenour	—	*	—	—%	—	*
R. Alan Marcum	—	*	—	—%	—	*
Kevin D. Lafferty	—	*	—	—%	—	*
Tony Vaughn	—	*	—	—%	—	*
Lyndon Taylor	—	*	—	—%	—	*
All directors and executive officers as a group (17 persons)	929,864	0.27%	—	—%	929,864	0.23%

* Less than 1%

(1) The address of each person listed above is 1722 Routh Street, Suite 1300, Dallas, Texas 75201, except for Devon Energy Corporation, whose address is 333 W. Sheridan Avenue, Oklahoma City, Oklahoma 73102, and Enfield Holdings, L.P., whose address is 301 Commerce Street, Fort Worth, Texas 76102.

(2) The percentages reflected in the column below are based on a total of 350,043,269 common units, including 20,338 restricted incentive units that are deemed beneficially owned.

(3) The percentages reflected in the column below are based on a total of 407,513,208 common units, which includes the units described in (2) above, and 57,469,939 Series B Preferred Units, which are convertible into common units on a one-for-one basis, subject to certain adjustments. Series C Preferred Units are perpetual preferred units that are not convertible into common units and therefore are not factored into the percent ownership calculations.

(4) Devon Gas Services, L.P. (“Devon Gas Services”) is the record holder of 87,128,717 common units; Southwestern Gas Pipeline, L.L.C. (“Southwestern Gas”) is the record holder of 7,531,883 common units; EnLink Midstream, Inc. (“EMI”) is the record holder of 20,280,252 common units; and Acacia Natural Gas Corp. I, Inc. (“Acacia”) is the record holder of 68,248,199 common units. As the indirect owner of (i) 100% of the outstanding limited and general partner interests in Devon Gas Services, (ii) 100% of the outstanding limited liability company interests of Southwestern Gas and (iii) 63.8% of the outstanding membership interest in EnLink Midstream, LLC (as well as 100% of the outstanding membership interest in EnLink Midstream, LLC’s managing member), which is the holder of 100% of the outstanding common stock of each of EMI and Acacia, Devon Energy Corporation may be deemed to beneficially own all of the common units held by Devon Gas Services, Southwestern Gas, EMI and Acacia, as applicable.

(5) On December 6, 2015, EnLink Midstream Partners, LP and Enfield Holdings, L.P. (“Enfield Holdings”) entered into that certain Convertible Preferred Unit Purchase Agreement (the “Purchase Agreement”), pursuant to which on January 7, 2016 Enfield Holdings purchased, in the aggregate, 50,000,000 Series B Preferred Units. Enfield Holdings Advisors, Inc. (“Enfield Holdings Advisors”) is the general partner of Enfield Holdings. Affiliates of The Goldman Sachs Group, Inc. (“GS Group”) and affiliates of TPG Global, LLC own interests in Enfield Holdings Advisors. GS Group, Goldman, Sachs & Co. (“Goldman Sachs”), West Street International Infrastructure Partners III, L.P. (“WS International”), West Street European Infrastructure Partners III, L.P. (“WS European”), West Street Global Infrastructure Partners III, L.P. (“WS Global”), Broad Street Principal Investments, L.L.C. (“BS Principal”), West Street Energy Partners Offshore - B AIV-1, L.P. (“WS Offshore B”), West Street Energy Partners AIV-1, L.P. (“WS AIV”), West Street Energy Partners Offshore AIV-1, L.P. (“WS Offshore AIV”), West Street Energy Partners Offshore Holding - B AIV-1, L.P. (“WS Holdings B”), Broad Street Infrastructure Advisors III, L.L.C. (“BS Infrastructure”), Broad Street Energy Advisors AIV-1, L.L.C. (“BS Energy AIV,” and together with WS International, WS European, WS Global, BS Principal, WS Offshore B, WS AIV, WS Offshore AIV, WS Holdings Band BS Infrastructure, the “GS Entities”) are the direct or indirect beneficial owners of WSIP Egypt Holdings, LP (“WSIP”) and WSEP Egypt Holdings, LP (“WSEP,” and together with WSIP, GS Group, Goldman Sachs and the GS Entities, the “GS Reporting Persons”), which hold 100 shares of common stock, and have appointed one of the two directors, of Enfield Holdings Advisors. David Bonderman and James G. Coulter are officers and sole shareholders of TPG Advisors VII, Inc. (together with the GS Reporting Persons and Messrs. Bonderman and Coulter, the “Reporting Persons”), which holds 100 shares of common stock, and has appointed one of the two directors, of Enfield Holdings Advisors. Because of the relationship between the Reporting Persons and Enfield Holdings, the Reporting Persons may be deemed to beneficially own the securities reported herein to the extent of the greater of their respective direct or indirect pecuniary interests in the profits or capital accounts of Enfield Holdings.

(6) Includes 37,999 common units owned of record by Mr. Lamb and 4,858 restricted incentive units that are deemed beneficially owned.

(7) Includes 497,478 common units owned of record by Mr. Davis. Of these common units, 50,042 are held by MK Holdings, LP, a family limited partnership, which Mr. Davis controls, and Mr. Davis disclaims beneficial ownership of these securities except to the extent of his pecuniary interest therein.

(8) Includes 29,117 common units owned of record by Mr. Echols and 2,580 restricted incentive units that are deemed beneficially owned.

(9) Includes 7,993 common units owned of record by Ms. Ricciardello and 2,580 restricted incentive units that are deemed beneficially owned.

(10) Includes 15,988 common units owned of record by Mr. Griffiths and 5,160 restricted incentive units that are deemed beneficially owned.

(11) Includes 60,233 common units owned of record by Mr. Vann and 5,160 restricted incentive units that are deemed beneficially owned.

EnLink Midstream, LLC and Devon Energy Corporation Ownership

The following table shows the beneficial ownership of the units of EnLink Midstream, LLC, as well as the beneficial ownership of shares of common stock of Devon Energy Corporation, as of February 14, 2018, held by:

- all the directors of EnLink Midstream GP, LLC;
- each named executive officer of EnLink Midstream GP, LLC; and
- all the directors and executive officers of EnLink Midstream GP, LLC as a group.

The percentage of total common units of EnLink Midstream, LLC beneficially owned is based on a total of180,901,963 units (including 18,594 restricted incentive units that are deemed beneficially owned) as of February 14, 2018. The percentage of total shares of Devon Energy Corporation beneficially owned is based on a total of 528,239,732 shares of common stock outstanding as of February 14, 2018.

	EnLink Midstream, LLC		Devon Energy Corporation	
Name of Beneficial Owner (1)	Common Units Beneficially Owned	Percent	Shares of Common Stock Beneficially Owned	Percent
Michael J. Garberding	174,632	*	500	*
Eric D. Batchelder	—	*	—	*
Mac Hummel	45,997	*	3,617	*
Benjamin D. Lamb (2)	31,866	*	—	*
Barry E. Davis (3)	1,796,663	*	—	*
Leldon E. Echols (4)	34,903	*	—	*
David A. Hager	—	*	428,382	*
Mary P. Ricciardello (5)	10,454	*	45,653	*
Scott A. Griffiths	—	*	—	*
Kyle D. Vann	—	*	—	*
Christopher Ortega	—	*	—	*
Jeff L. Ritenour	—	*	136,681	*
R. Alan Marcum	—	*	178,474	*
Kevin D. Lafferty	—	*	16,323	*
Tony Vaughn	—	*	205,894	*
Lyndon Taylor	—	*	114,991	*
All directors and executive officers as a group (17 persons)	2,138,909	1.18%	1,130,515	*

* Less than 1%.

(1) The address of each person listed above is 1722 Routh Street, Suite 1300, Dallas, Texas 75201, except for Devon Energy Corporation, whose address is 333 W. Sheridan Avenue, Oklahoma City, Oklahoma 73102.

(2) Includes 28,310 common units owned of record by Mr. Lamb and 3,556 restricted incentive units that are deemed beneficially owned.

(3) Includes 1,796,663 common units owned of record by Mr. Davis. Of these common units, 1,025,000 are held by MK Holdings, LP, a family limited partnership, which Mr. Davis controls, and Mr. Davis disclaims beneficial ownership of these securities except to the extent of his pecuniary interest therein.

(4) Includes 32,397 common units owned of record by Mr. Echols and 2,506 restricted incentive units that are deemed beneficially owned.

(5) Includes 7,948 common units owned of record by Ms. Ricciardello and 2,506 restricted incentive units that are deemed beneficially owned.

Beneficial Ownership of General Partner Interest

EnLink Midstream GP, LLC owns all of our general partner interest and all of our incentive distribution rights. EnLink Midstream GP, LLC is 100% indirectly owned by EnLink Midstream, LLC.

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)	2,652,846	(2)	$ 6.56	(3)	5,011,723
Equity Compensation Plans Not Approved by Security Holders	N/A		N/A		N/A

(1) Our Amended and Restated Long-Term Incentive Plan was approved by our unitholders, effective April 6, 2016, for the benefit of our officers, employees and directors. See "Item 11. Executive Compensation—Compensation Discussion and Analysis." The plan, as amended, provides for the issuance of a total of 14,070,000 common units under the plan.
(2) The number of securities includes 1,980,224 restricted incentive units that have been granted under our Amended and Restated Long-Term Incentive Plan that have not vested. In addition, the number of securities includes 585,285 performance unit awards granted under the plan, assuming the target distribution at the time of vesting. Actual issuance of these performance unit awards may range from 0% to 200% of the target distribution depending on performance actually attained.
(3) The exercise prices for outstanding options under the plan as of December 31, 2017 range from $3.11 to $31.58 per unit.

Item 13. Certain Relationships and Related Transactions and Director Independence

Our General Partner

Our operations and activities are managed by, and our officers are employed by, the Operating Partnership. Our general partner does not receive any management fee or other compensation in connection with its management of our business, but it is reimbursed for all direct and indirect expenses incurred on our behalf.

Our general partner owns the general partner interest inus and all of our incentive distribution rights. Our general partner is entitled to receive incentive distributions if the amount we distribute with respect to any quarter exceeds levels specified inour partnership agreement. Under the quarterly incentive distribution provisions,our general partner is entitled to 13.0% of amounts we distribute in excess of $0.25 per unit, 23% of the amounts we distribute in excess of $0.3125 per unit and 48.0% of amounts we distribute in excess of $0.375 per unit.

Relationship with Devon and EnLink Midstream, LLC

ENLC indirectly owns 88,528,451 common units, representing an approximate 21.7% limited partnership interest in us as of December 31, 2017. ENLC also indirectly owns our general partner and has the power to appoint all of the officers and directors of our general partner. ENLC is managed by its managing member, which is wholly-owned by Devon. Therefore, Devon indirectly controls our general partner, which has the sole authority to manage and operate our business. Devon also directly owns 94,660,600 limited partnership units, representing an approximate 23.1% majority ownership of our outstanding equity interests as ofDecember 31, 2017. Accordingly, through its control of our general partner, Devon effectively has the ability to veto some of our actions and to control our management.

Additionally, six of our directors, including David A. Hager, Kevin D. Lafferty, R. Alan Marcum, Jeff L. Ritenour, Lyndon Taylor and Tony Vaughn are officers of Devon. Those individuals do not receive separate compensation for their service on the Board, but they are entitled to indemnification related to their service as directors pursuant to the indemnification agreements as described below.

Related Party Transactions

Refer to "Item 8. Financial Statements and Supplementary information—Note 5" for information about our related party transactions, including commercial agreements with Devon.

Office Leases

In connection with the consummation of the Business Combination, we entered into three office lease agreements with a wholly-owned subsidiary of Devon pursuant to which we will lease office space at Devon's Bridgeport, Oklahoma City and Cresson office buildings. Rent payable to Devon under these lease agreements is $174,000, $31,000 and $66,000, respectively, on an annual basis.

Certain Relationships

From time to time, we may do business with other companies affiliated with TPG, which holds an interest in Enfield Holdings, L.P., the beneficial owner of our Series B Preferred Units, or with Natural Resources XI, L.P. or Kinder Morgan, Inc., our joint venture partners in the Delaware Basin JV and Cedar Cove JV, respectively. We believe that any such arrangements have been or will be conducted on an arms-length basis.

Indemnification of Directors and Officers

We have entered into indemnification agreements (the "Indemnification Agreements") with each of the General Partner's directors and executive officers (collectively, the "Indemnitees"). Under the terms of the Indemnification Agreements, we agree to indemnify and hold each Indemnitee harmless, subject to certain conditions, against any and all losses, claims, damages, liabilities, expenses (including legal fees and expenses), judgments, fines, ERISA excise taxes, penalties, interest, settlements or other amounts arising from any and all threatened, pending or completed claims, demands, actions, suits or proceedings, whether civil, criminal, administrative or investigative, and whether formal or informal and including appeals, in which the Indemnitee is involved, or is threatened to be involved, as a party or otherwise, because the Indemnitee is or was a director, manager or officer of the General Partner or us, or is or was serving at the request of the General Partner or us as a manager, managing member, General Partner, director, officer, fiduciary, or trustee of another entity, organization or person of any nature. We have also agreed to advance the expenses of an Indemnitee relating to the foregoing. To the extent that a change in the laws of the State of Delaware permits greater indemnification under any statute, agreement, organizational document or governing document than would be afforded under the Indemnification Agreements as of the date of the Indemnification Agreements, the Indemnitee shall enjoy the greater benefits so afforded by such change.

Approval and Review of Related Party Transactions

If we contemplate entering into a transaction, other than a routine or in the ordinary course of business transaction, in which a related person will have a direct or indirect material interest, the proposed transaction is submitted for consideration to the Board or our senior management, as appropriate. If the Board is involved in the approval process, it determines whether it is advisable to refer the matter to the Conflicts Committee of the Board, comprised entirely of independent directors, as constituted under our operating agreement. The Conflicts Committee operates pursuant to its written charter and our operating agreement. If a matter is referred to the Conflicts Committee, the Conflicts Committee obtains information regarding the proposed transaction from management and determines whether it is advisable to engage independent legal counsel or an independent financial advisor to advise the members of the committee regarding the transaction. If the committee retains such counsel or financial advisor, it considers the advice and, in the case of a financial advisor, such advisor's opinion as to whether the transaction is fair and reasonable to us and to our unitholders.

Director Independence

See "Item 10. Directors, Executive Officers and Corporate Governance" for information regarding director independence.

Item 14. Principal Accounting Fees and Services

Audit Fees

The fees for professional services rendered for the audit of our annual financial statements for the fiscal years ended December 31, 2017, 2016 and 2015, review of our internal control procedures for the fiscal years ended December 31, 2017, 2016 and 2015, and the reviews of the financial statements included in our quarterly reports on Form 10-Q or services that are normally provided by KPMG in connection with statutory or regulatory filings or engagements for each of those fiscal years were $1.7 million, $1.9 million and $2.0 million, respectively. These amounts also included fees associated with comfort letters and consents related to debt and equity offerings.

Audit-Related Fees

KPMG did not perform any assurance and related services in connection with the audit or review of our financial statements for the fiscal years ended December 31, 2017, 2016 and 2015 that were not included in the audit fees listed above.

Tax Fees

KPMG did not perform any tax related services for the years ended December 31, 2017, 2016 and 2015.

All Other Fees

KPMG did not render services to us, other than those services covered in the section captioned "Audit Fees" for the fiscal years ended December 31, 2017, 2016 and 2015.

Audit Committee Approval of Audit and Non-Audit Services

All audit and non-audit services and any services that exceed the annual limits set forth in our annual engagement letter for audit services must be pre-approved by the Audit Committee. In 2017, the Audit Committee did not pre-approve the use of KPMG for any non-audit related services. The Chairman of the Audit Committee is authorized by the Audit Committee to pre-approve additional KPMG audit and non-audit services between Audit Committee meetings, provided that the additional services do not affect KPMG's independence under applicable Securities and Exchange Commission rules and any such pre-approval is reported to the Audit Committee at its next meeting.

PART IV

Item 15. Exhibits and Financial Statement Schedules

(a) Financial Statements and Schedules

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

2. Exhibits

The exhibits filed as part of this report are as follows (exhibits incorporated by reference are set forth with the name of the registrant, the type of report and registration number or last date of the period for which it was filed, and the exhibit number in such filing):

Number		Description
2.1 **	—	TOM-STACK Securities Purchase Agreement, dated as of December 6, 2015, among Tall Oak Midstream, LLC, FE-STACK, LLC, TOM-STACK Holdings, LLC, TOM-STACK, LLC, EnLink TOM Holdings, LP and EnLink Midstream, LLC and, solely for purposes of Section 6.19 thereof, EnLink Midstream Partners, LP (incorporated by reference to Exhibit 2.1 to our Current Report on Form 8-K dated December 7, 2015, filed with the Commission on December 7, 2015, file No. 001-36340).
2.2 **	—	TOMPC Securities Purchase Agreement, dated as of December 6, 2015, among TOMPC LLC, Tall Oak Midstream, LLC, EnLink TOM Holdings, LP, and EnLink Midstream, LLC and, solely for purposes of Section 6.19 thereof, EnLink Midstream Partners, LP (incorporated by reference to Exhibit 2.2 to our Current Report on Form 8-K dated December 7, 2015, filed with the Commission on December 7, 2015, file No. 001-36340).
3.1	—	Certificate of Limited Partnership of EnLink Midstream Partners, LP (incorporated by reference to Exhibit 3.1 to our Registration Statement on Form S-1, file No. 333-97779).
3.2	—	Certificate of Amendment to the Certificate of Limited Partnership of EnLink Midstream Partners, LP (incorporated by reference to Exhibit 3.2 to our Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2012, filed with the Commission on August 7, 2012, file No. 000-50067).
3.3	—	Second Amendment to the Certificate of Limited Partnership of EnLink Midstream Partners, LP (incorporated by reference to Exhibit 3.3 to our Current Report on Form 8-K dated March 6, 2014, filed with the Commission on March 11, 2014, file No. 001-36340).
3.4	—	Third Amendment to the Certificate of Limited Partnership of EnLink Midstream Partners, LP (incorporated by reference to Exhibit 3.1 to our Current Report on Form 8-K dated June 16, 2017, filed with the Commission on June 19, 2017, file No. 001-36340).
3.5	—	Ninth Amended and Restated Agreement of Limited Partnership of EnLink Midstream Partners, LP, dated as of September 21, 2017 (incorporated by reference to Exhibit 3.1 to our Current Report on Form 8-K dated September 21, 2017, filed with the Commission on September 21, 2017, file No. 001-36340).
3.6	—	Amendment No. 1 to Ninth Amended and Restated Agreement of Limited Partnership of EnLink Midstream Partners, LP, dated as of December 12, 2017 (incorporated by reference to Exhibit 3.1 to our Current Report on Form 8-K dated December 12, 2017, filed with the Commission on December 14, 2017, file No. 001-36340).
3.7	—	Certificate of Formation of EnLink Midstream GP, LLC (incorporated by reference to Exhibit 3.7 to our Registration Statement on Form S-1, file No. 333-97779).
3.8	—	Certificate of Amendment to the Certificate of Formation of EnLink Midstream GP, LLC (incorporated by reference to Exhibit 3.12 to our Registration Statement on Form S-3, file No. 333-194465).
3.9	—	Third Amended and Restated Limited Liability Company Agreement of EnLink Midstream GP, LLC, dated as of July 7, 2014 (incorporated by reference to Exhibit 3.2 to our Current Report on Form 8-K dated July 7, 2014, filed with the Commission on July 7, 2014, file No. 001-36340).
3.10	—	Amendment No. 1 to Third Amended and Restated Limited Liability Company Agreement of EnLink Midstream GP, LLC, dated as of January 7, 2016 (incorporated by reference to Exhibit 3.2 to our Current Report on Form 8-K dated January 12, 2016, filed with the Commission on January 12, 2016, file No. 001-36340).
4.1	—	Specimen Unit Certificate for Common Units (incorporated by reference to Exhibit 12 to our Registration Statement on Form 8-A, filed with the Commission on March 7, 2014, file No. 001-36340).
4.2	—	Unitholder Agreement, dated as of March 7, 2014, by and among Devon Energy Corporation, Devon Gas Corporation, Devon Gas Services, L.P., Southwestern Gas Pipeline, Inc. and EnLink Midstream Partners, LP (incorporated by reference to Exhibit 4.1 to our Current Report on Form 8-K dated March 6, 2014, filed with the Commission on March 11, 2014, file No. 001-36340).

4.3		—	Indenture, dated as of March 19, 2014, by and between EnLink Midstream Partners, LP and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.2 to our Current Report on Form 8-K dated March 19, 2014, filed with the Commission on March 21, 2014, file No. 001-36340).
4.4		—	First Supplemental Indenture, dated as of March 19, 2014, by and between EnLink Midstream Partners, LP and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.3 to our Current Report on Form 8-K dated March 19, 2014, filed with the Commission on March 21, 2014, file No. 001-36340).
4.5		—	Second Supplemental Indenture, dated as of November 12, 2014, by and between EnLink Midstream Partners, LP and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.3 to our Current Report on Form 8-K dated November 6, 2014, filed with the Commission on November 12, 2014, file No. 001-36340).
4.6		—	Third Supplemental Indenture, dated as of May 12, 2015, by and between EnLink Midstream Partners, LP and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.3 to our Current Report on Form 8-K dated May 7, 2015, filed with the Commission on May 12, 2015).
4.7		—	Fourth Supplemental Indenture, dated as of July 14, 2016, by and between EnLink Midstream Partners, LP and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.2 to our Current Report on Form 8-K dated July 11, 2016, filed with the Commission on July 14, 2016, file No. 001-36340).
4.8		—	Fifth Supplemental Indenture, dated as of May 11, 2017, by and between EnLink Midstream Partners, LP and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.2 to our Current Report on Form 8-K dated May 11, 2017, filed with the Commission on May 11, 2017).
4.9		—	Registration Rights Agreement, dated as of January 7, 2016, by and between EnLink Midstream Partners, LP and Enfield Holdings, L.P. (incorporated by reference to Exhibit 4.1 to our Current Report on Form 8-K dated January 12, 2016, filed with the Commission on January 12, 2016, file No. 001-36340).
10.1		—	Preferential Rights Agreement, dated as of March 7, 2014, by and among Crosstex Energy, Inc., EnLink Midstream Partners, LP and EnLink Midstream, LLC (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K dated March 6, 2014, filed with the Commission on March 11, 2014, file No. 001-36340).
10.2		—	Gas Gathering and Processing Contract-Bridgeport Plant, dated as of March 7, 2014, by and between Devon Gas Services, L.P. and EnLink Midstream Services, LLC (incorporated by reference to Exhibit 10.2 to our Current Report on Form 8-K dated March 6, 2014, filed with the Commission on March 11, 2014, file No. 001-36340).
10.3		—	Gas Gathering and Processing Contract-Cana Plant, dated as of March 7, 2014, by and between Devon Gas Services, L.P. and EnLink Midstream Services, LLC (incorporated by reference to Exhibit 10.3 to our Current Report on Form 8-K dated March 6, 2014, filed with the Commission on March 11, 2014, file No. 001-36340).
10.4		—	Gas Gathering and Processing Contract-East Johnson County System, dated as of March 7, 2014, by and between Devon Gas Services, L.P. and EnLink Midstream Services, LLC (incorporated by reference to Exhibit 10.5 to our Current Report on Form 8-K dated March 6, 2014, filed with the Commission on March 11, 2014, file No. 001-36340).
10.5		—	Form of Indemnification Agreement (incorporated by reference to Exhibit 10.6 to our Current Report on Form 8-K dated March 6, 2014, filed with the Commission on March 11, 2014, file No. 001-36340).
10.6		—	Form of Indemnification Agreement (incorporated by reference to Exhibit 10.8 to EnLink Midstream, LLC's Current Report on Form 8-K dated March 7, 2014, filed with the Commission on March 11, 2014, file No. 001-36336).
10.7	†	—	EnLink Midstream GP, LLC Long-Term Incentive Plan (the "GP Plan"), as amended and restated in 2016 (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K dated March 9, 2016, filed with the Commission on March 9, 2016, file No. 001-36340).
10.8	†	—	EnLink Midstream, LLC 2014 Long-Term Incentive Plan (the "2014 plan") (incorporated by reference to Exhibit 4.4 to EnLink Midstream, LLC's Registration Statement on Form S-8 dated March 7, 2014, filed with the Commission on March 7, 2014, file No. 333-194395).
10.9	†	—	Form of Amended and Restated Severance Agreement (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K dated October 31, 2014, filed with the Commission on November 3, 2014, file No. 001-36340).
10.10		—	Form of Amended and Restated Change in Control Agreement (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K dated June 12, 2015, filed with the Commission June 15, 2015, file No. 001-36340).
10.11	†	—	Form of Restricted Unit Agreement made under the GP Plan (incorporated by reference to Exhibit 10.9 to our Annual Report on Form 10-K for the year ended December 31, 2009, file No. 000-50067).

10.12	†	—	Form of Restricted Incentive Unit Agreement made under the GP Plan (incorporated by reference to Exhibit 10.2 to our Current Report on Form 8-K dated May 9, 2013, filed with the Commission on May 13, 2013, file No. 000-50067).
10.13	†	—	Form of Restricted Incentive Unit Agreement made under the 2014 Plan (Executive Form) (incorporated by reference to Exhibit 4.6 to EnLink Midstream, LLC's Registration Statement on Form S-8, file No. 333-194395).
10.14	†	—	Form of Restricted Incentive Unit Agreement made under the 2014 Plan (Employee Form) (incorporated by reference to Exhibit 4.7 to EnLink Midstream, LLC's Registration Statement on Form S-8, file No. 333-194395).
10.15		—	Credit Agreement, dated as of February 20, 2014, by and among Crosstex Energy, L.P., Bank of America, N.A., as Administrative Agent, Swing Line Lender and L/C Issuer thereunder, Citibank, N.A. and Wells Fargo Bank, National Association, as Co-Syndication Agents, Royal Bank of Canada and Bank of Montreal, as Co-Documentation Agents, and the other lenders party thereto (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K dated February 20, 2014, filed with the Commission on February 21, 2014, file No. 000-50067).
10.16		—	First Amendment to Credit Agreement, dated as of December 23, 2015, by and among EnLink Midstream Partners, LP, Bank of America, N.A., as Administrative Agent, and the lenders party thereto (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K dated December 29, 2015, filed with the Commission on December 29, 2015, file No. 001-36340).
10.17		—	Commitment Increase and Extension Agreement, dated as of February 5, 2015, by and among EnLink Midstream Partners, LP, the Lenders party thereto, and Bank of America, N.A., as an L/C Issuer, as Swing Line Lender, and as Administrative Agent for the Lenders (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K dated February 5, 2015, filed with the Commission on February 11, 2015, file No. 001-36340).
10.18	†	—	Form of Performance Unit Agreement made under the GP Plan (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K dated January 30, 2015, filed with the Commission February 5, 2015, file No. 001-36340).
10.19	†	—	Form of Performance Unit Agreement made under the 2014 Plan (incorporated by reference to Exhibit 10.2 to our Current Report on Form 8-K dated January 30, 2015, filed with the Commission February 5, 2015, file No. 001-36340).
10.20	†	—	Form of Restricted Incentive Unit Agreement made under the GP Plan (incorporated by reference to Exhibit 10.3 to our Current Report on Form 8-K dated January 30, 2015, filed with the Commission February 5, 2015, file No. 001-36340).
10.21	†	—	Form of Restricted Incentive Unit Agreement made under the 2014 Plan (incorporated by reference to Exhibit 10.4 to our Current Report on Form 8-K dated January 30, 2015, filed with the Commission February 5, 2015, file No. 001-36340).
10.22		—	Convertible Preferred Unit Purchase Agreement, dated as of December 6, 2015, by and between EnLink Midstream Partners, LP and Enfield Holdings, L.P. (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K dated December 7, 2015, filed with the Commission on December 7, 2015, file No. 001-36340).
10.23		—	Board Representation Agreement, dated as of January 7, 2016, by and among EnLink Midstream GP, LLC, EnLink Midstream Partners, LP, EnLink Midstream, Inc. and TPG VII Management, LLC (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K dated January 12, 2016, filed with the Commission on January 12, 2016, file No. 001-36340).
10.24	†	—	Form of Performance Unit Agreement made under the GP Plan (incorporated by reference to Exhibit 10.1 to our Quarterly Report on Form 10-Q for the quarter ended March 31, 2017, file No. 001-36340).
10.25	†	—	Form of Performance Unit Agreement made under the LLC Plan (incorporated by reference to Exhibit 10.2 to our Quarterly Report on Form 10-Q for the quarter ended March 31, 2017, file No. 001-36340).
10.26	†	—	Form of Restricted Incentive Unit Agreement made under the GP Plan (incorporated by reference to Exhibit 10.3 to our Quarterly Report on Form 10-Q for the quarter ended March 31, 2017, file No. 001-36340).
10.27	†	—	Form of Restricted Incentive Unit Agreement made under the LLC Plan (incorporated by reference to Exhibit 10.4 to our Quarterly Report on Form 10-Q for the quarter ended March 31, 2017, file No. 001-36340).
12.1	*	—	Ratio of Earnings to Fixed Charges.
21.1	*	—	List of Subsidiaries.
23.1	*	—	Consent of KPMG LLP.
31.1	*	—	Certification of the Principal Executive Officer.
31.2	*	—	Certification of the Principal Financial Officer.

32.1	*	—	Certification of the Principal Executive Officer and the Principal Financial Officer of the Partnership pursuant to 18 U.S.C. Section 1350.
101	*	—	The following financial information from EnLink Midstream Partners, LP's Annual Report on Form 10-K for the year ended December 31, 2017, formatted in XBRL (eXtensible Business Reporting Language): (i) Consolidated Statements of Operations for the years ended December 31, 2017, 2016 and 2015, (ii) Consolidated Balance Sheets as of December 31, 2017 and 2016, (iii) Consolidated Statements of Cash Flows for the years ended December 31, 2017, 2016 and 2015, (iv) Consolidated Statements of Changes in Partners' Equity for the years ended December 31, 2017, 2016 and 2015 and (v) the Notes to Consolidated Financial Statements.

* Filed herewith.

** In accordance with the instruction on Item 601(b)(2) of Regulation S-K, the exhibits and schedules to Exhibits 2.1 and 2.2 are not filed herewith. The agreements identify such exhibits and schedules, including the general nature of their content. We undertake to provide such exhibits and schedules to the Commission upon request.

† As required by Item 15(a)(3), this Exhibit is identified as a compensatory benefit plan or arrangement.

Table of Contents

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

EnLink Midstream Partners, LP

By: EnLink Midstream GP, LLC, its general partner

February 21, 2018

By: /s/ MICHAEL J. GARBERDING

Michael J. Garberding,

President and Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below on the dates indicated by the following persons on behalf of the Registrant and in the capacities with EnLink Midstream GP, LLC, general partner of the Registrant, indicated.

Signature	Title	Date
/s/ MICHAEL J. GARBERDING Michael J. Garberding	President and Chief Executive Officer (Principal Executive Officer)	February 21, 2018
/s/ BARRY E. DAVIS Barry E. Davis	Executive Chairman of the Board	February 21, 2018
/s/ LELDON E. ECHOLS Leldon E. Echols	Director	February 21, 2018
/s/ SCOTT A. GRIFFITHS Scott A. Griffiths	Director	February 21, 2018
/s/ DAVID A. HAGER David A. Hager	Director	February 21, 2018
/s/ KEVIN D. LAFFERTY Kevin D. Lafferty	Director	February 21, 2018
/s/ R. ALAN MARCUM R. Alan Marcum	Director	February 21, 2018
/s/ CHRISTOPHER ORTEGA Christopher Ortega	Director	February 21, 2018
/s/ MARY P. RICCIARDELLO Mary P. Ricciardello	Director	February 21, 2018
/s/ JEFF L. RITENOUR Jeff L. Ritenour	Director	February 21, 2018
/s/ LYNDON TAYLOR Lyndon Taylor	Director	February 21, 2018
/s/ KYLE D. VANN Kyle D. Vann	Director	February 21, 2018
/s/ TONY VAUGHN Tony Vaughn	Director	February 21, 2018
/s/ ERIC D. BATCHELDER Eric D. Batchelder	Executive Vice President and Chief Financial Officer (Principal Financial and Accounting Officer)	February 21, 2018

Exhibit 12.1

RATIO OF EARNINGS TO FIXED CHARGES

	Year Ended December 31,				
	2017	2016	2015	2014	2013
	(In millions)				
Earnings Before Fixed charges:					
Earnings from continuing operations before non-controlling interest or tax	$ 130.8	$ (572.0)	$ (1,378.7)	$ 331.3	$ 186.1
Capitalized interest	(6.3)	(7.2)	(7.7)	(11.8)	—
Amortization of capitalized interest	1.7	1.4	0.9	0.5	—
Income from unconsolidated affiliates	(9.6)	19.9	(20.4)	(18.9)	(14.8)
Distributed income from unconsolidated affiliates	13.5	57.7	42.7	23.7	12.0
Non-controlling interest	(5.9)	8.1	0.4	0.2	—
Fixed Charges	215.7	195.3	110.2	59.2	—
Total earnings before fixed charges	$ 339.9	$ (296.8)	$ (1,252.6)	$ 384.2	$ 183.3
Fixed charges:					
Interest expense	$ 187.9	$ 188.1	$ 102.5	$ 47.4	$ —
Capitalized interest	6.3	7.2	7.7	11.8	—
Preferred Distributions	21.5	—	—	—	—
Total fixed charges	$ 215.7	$ 195.3	$ 110.2	$ 59.2	$ —
Ratio of earnings to fixed charges	1.6	N/A	N/A	6.5	N/A
Deficiency	$ —	$ (492.1)	$ (1,362.8)	$ —	$ —

Exhibit 21.1

List of Subsidiaries

Name of Subsidiary	State of Organization
Acacia Natural Gas, L.L.C.	Delaware
Appalachian Oil Purchasers, LLC	Delaware
Ascension Pipeline Company, LLC	Delaware
Bridgeline Holdings, L.P.	Delaware
Cedar Cove Midstream LLC	Delaware
Chandeleur Pipe Line, LLC	Delaware
Coronado Midstream LLC	Texas
Delaware G&P, LLC	Delaware
Delaware Processing LLC	Delaware
EnLink Appalachian Compression, LLC	Delaware
EnLink Calcasieu, LLC	Delaware
EnLink Crude Marketing, LLC	Delaware
EnLink Crude Oil, Inc.	Texas
EnLink Crude Pipeline, LLC	Delaware
EnLink Crude Purchasing LLC	Texas
EnLink Delaware Crude Pipeline, LLC	Texas
EnLink DC Gathering Company JV	Texas
EnLink Energy GP, LLC	Delaware
EnLink Gas Marketing, LP	Texas
EnLink GOM, LLC	Delaware
EnLink LIG Liquids, LLC	Louisiana
EnLink LIG, LLC	Louisiana
EnLink Louisiana Gathering, LLC	Louisiana
EnLink Matli Holdings, LLC	Delaware
EnLink Midstream Finance Corporation	Delaware
EnLink Midstream Holdings GP, LLC	Delaware
EnLink Midstream Holdings, LP	Delaware
EnLink Midstream Operating GP, LLC	Delaware
EnLink Midstream Operating, LP	Delaware
EnLink Midstream Services, LLC	Texas
EnLink NGL Marketing, LP	Texas
EnLink NGL Pipeline, LP	Texas
EnLink North Texas Gathering, LP	Texas
EnLink Ohio Compression, LLC	Delaware
EnLink Oklahoma Crude Gathering, LLC	Delaware
EnLink Oklahoma Gas Processing, LP	Delaware
EnLink Oklahoma Pipeline, LLC	Delaware
EnLink ORV Holdings, Inc.	Delaware
EnLink Pelican, LLC	Delaware
EnLink Permian, LLC	Texas
EnLink Permian II, LLC	Texas
EnLink Processing Services, LLC	Delaware
EnLink STACK Crude Gathering LLC	Delaware
EnLink Texas NGL Pipeline, LLC	Texas
EnLink Texas Processing, LP	Texas
EnLink TOM Holdings, LP	Delaware
EnLink Tuscaloosa, LLC	Louisiana
Kentucky Oil Gathering, LLC	Delaware
M & B Gas Services, LLC	Delaware
Ohio Oil Gathering II, LLC	Delaware
Ohio Oil Gathering III, LLC	Delaware
Ohio River Valley Pipeline, LLC	Delaware
OOGC Disposal Company I, LLC	Delaware
Sabine Hub Services LLC	Delaware
Sabine Pass Plant Facility Joint Venture	Texas
Sabine Pipe Line LLC	Delaware
SWG Pipeline, L.L.C.	Texas
TOMPC LLC	Delaware
TOM-STACK, LLC	Delaware
Victoria Express Pipeline, L.L.C.	Texas
West Virginia Oil Gathering, LLC	Delaware

Exhibit 23.1

Consent of Independent Registered Public Accounting Firm

The Partners
EnLink Midstream Partners, LP

We consent to the incorporation by reference in the registration statements No.333-107025, 333-127645, 333-159140,333-188678 and 333-210641 on Form S-8, No 333-194465 and 333-199618 on Form S-3 of EnLink Midstream Partners, LP and subsidiaries of our report dated February 21, 2018, with respect to the consolidated balance sheets of EnLink Midstream Partners, LP and subsidiaries as of December 31, 2017 and 2016, and the related consolidated statements of operations, changes in partners' equity, and cash flows, for each of the years in the three-year period ended December 31, 2017, and the effectiveness of internal control over financial reporting as of December 31, 2017, which report appears in the December 31, 2017 annual report on Form 10-K of EnLink Midstream Partners, LP and subsidiaries.

/s/ KPMG LLP

Dallas, Texas
February 21, 2018

Exhibit 31.1

CERTIFICATIONS

I, Michael J. Garberding, certify that:

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

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

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

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

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

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

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

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

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

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

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

Date: February 21, 2018

/s/ MICHAEL J. GARBERDING

MICHAEL J. GARBERDING

,

President and Chief Executive Officer

(principal executive officer)

Exhibit 31.2

CERTIFICATIONS

I, Eric D. Batchelder, certify that:

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

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

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

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

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

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

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

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

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

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

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

Date: February 21, 2018

/s/ ERIC D. BATCHELDER

ERIC D. BATCHELDER
Executive Vice President and Chief Financial Officer
(principal financial and accounting officer)

Exhibit 32.1

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

In connection with the Annual Report of EnLink Midstream Partners, LP (the “Registrant”) on Form 10-K of EnLink Midstream Partners, LP for the year ended December 31, 2017 as filed with the Securities and Exchange Commission on the date hereof (the “Report”), each of the undersigned, Michael J. Garberding, Chief Executive Officer of EnLink Midstream GP, LLC, and Eric D. Batchelder, Chief Financial Officer of EnLink Midstream GP, LLC, certifies, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to his knowledge:

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

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

Date: February 21, 2018	/s/ MICHAEL J. GARBERDING
	Michael J. Garberding
	Chief Executive Officer
Date: February 21, 2018	/s/ ERIC D. BATCHELDER
	Eric D. Batchelder
	Chief Financial Officer

A signed original of this written statement required by Section 906 has been provided to the Registrant and will be retained by the Registrant and furnished to the Securities and Exchange Commission or its staff upon request. The foregoing certification is being furnished to the Securities and Exchange Commission as an exhibit to the Report.