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

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

For the fiscal year ended December 31, 2019

OR

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

For the transition period from to

Commission file 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	Trading Symbol	Name of Exchange on which Registered
None.	None.	None.

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

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

Large accelerated filer	☐	Accelerated filer	☐
Non-accelerated filer	☒	Smaller reporting company	☐
Emerging growth company	☐		☐

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

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

At February 19, 2020, the Registrant had 144,358,720 common units outstanding, all of which were held by our affiliate, EnLink Midstream, LLC.

DOCUMENTS INCORPORATED BY REFERENCE:
None.

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DEFINITIONS

The following terms as defined are used in this document:

Defined Term	Definition
/d	Per day.
2014 EDA	Equity Distribution Agreement entered into by ENLK in November 2014 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 ENLK's common units from time to time through an "at the market" equity offering program.
2014 Plan	ENLC's 2014 Long-Term Incentive Plan.
2017 EDA	Equity Distribution Agreement entered into by ENLK in August 2017 with UBS Securities LLC, Barclays Capital Inc., BMO Capital Markets Corp., Merrill Lynch, Pierce, Fenner & Smith Incorporated, Citigroup Global Markets Inc., Jefferies LLC, Mizuho Securities USA LLC, RBC Capital Markets, LLC, SunTrust Robinson Humphrey, Inc., and Wells Fargo Securities, LLC (collectively, the "ENLK Sales Agents") to sell up to $600.0 million in aggregate gross sales of ENLK's common units from time to time through an "at the market" equity offering program.
Acacia	Acacia Natural Gas Corp. I, Inc.
AMZ	Alerian MLP Index for Master Limited Partnerships.
ASC	The FASB Accounting Standards Codification.
ASC 606	ASC 606, *Revenue from Contracts with Customers.*
ASC 842	ASC 842, *Leases.*
Ascension JV	Ascension Pipeline Company, LLC, a joint venture between a subsidiary of ENLK and a subsidiary of Marathon Petroleum Corporation in which ENLK owns a 50% interest and Marathon Petroleum Corporation owns a 50% interest. The Ascension JV, which began operations in April 2017, owns an NGL pipeline that connects ENLK's Riverside fractionator to Marathon Petroleum Corporation's Garyville refinery.
ASU	The FASB Accounting Standards Update.
Avenger	Avenger crude oil gathering system, a crude oil gathering system in the northern Delaware Basin.
Bbls	Barrels.
Bcf	Billion cubic feet.
Black Coyote	Black Coyote crude oil gathering system, a crude oil gathering system in the STACK.
BLM	Bureau of Land Management.
Cedar Cove JV	Cedar Cove Midstream LLC, a joint venture between a subsidiary of ENLK and a subsidiary of Kinder Morgan, Inc. in which ENLK owns a 30% interest and Kinder Morgan, Inc. owns a 70% interest. The Cedar Cove JV, which was formed in November 2016, owns gathering and compression assets in Blaine County, Oklahoma, located in the STACK play.
CFTC	U.S. Commodity Futures Trading Commission.
CNOW	Central Northern Oklahoma Woodford Shale.
CO_2	Carbon dioxide.
Commission	U.S. Securities and Exchange Commission.
Consolidated Credit Facility	A $1.75 billion unsecured revolving credit facility entered into by ENLC that matures on January 25, 2024, which includes a $500.0 million letter of credit subfacility. The Consolidated Credit Facility was available upon closing of the Merger and is guaranteed by ENLK.
Delaware Basin JV	Delaware G&P LLC, a joint venture between a subsidiary of ENLK and an affiliate of NGP in which ENLK owns a 50.1% interest and NGP owns a 49.9% interest. The Delaware Basin JV, which was formed in August 2016, owns the Lobo processing facilities located in the Delaware Basin in Texas.
Devon	Devon Energy Corporation.
ECP System	EnLink Crude Purchasing System. The ECP System includes assets that were acquired through the acquisition of LPC Crude Oil Marketing LLC in January 2015.
EMI	EnLink Midstream, Inc.
Enfield	Enfield Holdings, L.P.
ENLC	EnLink Midstream, LLC.
ENLC Class C Common Units	A class of non-economic ENLC common units issued to Enfield immediately prior to the Merger equal to the number of Series B Preferred Units held by Enfield immediately prior to the effective time of the Merger, in order to provide Enfield with certain voting rights with respect to ENLC.
ENLK	EnLink Midstream Partners, LP or, when applicable, EnLink Midstream Partners, LP together with its consolidated subsidiaries. Also referred to as the "Partnership."

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ENLK Credit Facility	A $1.5 billion unsecured revolving credit facility entered into by ENLK that would have matured on March 6, 2020, which included a $500.0 million letter of credit subfacility. The ENLK Credit Facility was terminated on January 25, 2019 in connection with the consummation of the Merger.
EOGP	EnLink Oklahoma Gas Processing, LP or EnLink Oklahoma Gas Processing, LP together with, when applicable, its consolidated subsidiaries. Since January 31, 2019, EOGP has been a wholly-owned subsidiary of the Operating Partnership.
FASB	Financial Accounting Standards Board.
FERC	Federal Energy Regulatory Commission.
GAAP	Generally accepted accounting principles in the United States of America.
Gal	Gallons.
GCF	Gulf Coast Fractionators, which owns an NGL fractionator in Mont Belvieu, Texas. ENLK owns 38.75% of GCF.
GHG	Greenhouse gas.
GIP	Global Infrastructure Management, LLC, an independent infrastructure fund manager, itself, its affiliates, or managed fund vehicles, including GIP III Stetson I, L.P., GIP III Stetson II, L.P., and their affiliates.
GIP Transaction	On July 18, 2018, subsidiaries of Devon closed a transaction to sell all of their equity interests in ENLK, ENLC, and the managing member of ENLC to GIP.
Goldman Sachs	Goldman Sachs Group, Inc.
GP Plan	EnLink Midstream GP, LLC's Long-Term Incentive Plan.
Greater Chickadee	Crude oil gathering system in Upton and Midland counties, Texas in the Permian Basin.
Gross Operating Margin	Revenue less cost of sales. Gross Operating Margin is a non-GAAP financial measure. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Non-GAAP Financial Measures" for other information.
HEP	Howard Energy Partners, LP. ENLK sold its 31% ownership interest in HEP in March 2017.
ISDAs	International Swaps and Derivatives Association Agreements.
Mcf	Thousand cubic feet.
MEGA system	Midland Energy Gathering Area system in Midland, Martin, and Glasscock counties, Texas.
Merger	On January 25, 2019, NOLA Merger Sub merged with and into ENLK with ENLK continuing as the surviving entity and a subsidiary of ENLC.
Merger Agreement	The Agreement and Plan of Merger, dated as of October 21, 2018, by and among ENLK, the general partner of ENLK, ENLC, the managing member of ENLC, and NOLA Merger Sub related to the Merger.
MMbbls	Million barrels.
MMbtu	Million British thermal units.
MMcf	Million cubic feet.
MVC	Minimum volume commitment.
NGL	Natural gas liquid.
NGP	NGP Natural Resources XI, LP.
NOLA Merger Sub	NOLA Merger Sub, LLC, previously a wholly-owned subsidiary of ENLC prior to the Merger.
NYSE	New York Stock Exchange.
Operating Partnership	EnLink Midstream Operating, LP, a Delaware limited partnership and wholly-owned subsidiary of ENLK.
ORV	ENLK's Ohio River Valley crude oil, condensate stabilization, natural gas compression, and brine disposal assets in the Utica and Marcellus shales.
OTC	Over-the-counter.
Permian Basin	A large sedimentary basin that includes the Midland and Delaware Basins primarily in West Texas and New Mexico.
POL contracts	Percentage-of-liquids contracts.
POP contracts	Percentage-of-proceeds contracts.
Redbud	Redbud crude oil gathering system, a crude oil gathering system in the STACK.
Series B Preferred Unit	ENLK's Series B Cumulative Convertible Preferred Unit.
Series C Preferred Unit	ENLK's Series C Fixed-to-Floating Rate Cumulative Redeemable Perpetual Preferred Unit.
STACK	Sooner Trend Anadarko Basin Canadian and Kingfisher Counties in Oklahoma.
Term Loan	An $850.0 million term loan entered into by ENLK on December 11, 2018 with Bank of America, N.A., as Administrative Agent, Bank of Montreal and Royal Bank of Canada, as Co-Syndication Agents, Citibank, N.A. and Wells Fargo Bank, National Association, as Co-Documentation Agents, and the lenders party thereto, which ENLC assumed in connection with the Merger and the obligations of which ENLK guarantees.

Thunderbird Plant	A gas processing plant in Central Oklahoma.
Tiger Plant	A gas processing plant in the Delaware Basin.
TPG	TPG Global, LLC.
VEX	ENLK's Victoria Express Pipeline and related truck terminal and storage assets located in the Eagle Ford Shale in South Texas.
White Star	White Star Petroleum, LLC.

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").

ENLINK MIDSTREAM PARTNERS, LP

PART I

Item 1. Business

General

ENLK is a Delaware limited partnership formed in 2002. Our business activities are conducted through 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 Commission: 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. Additionally, filings are available on the Commission's website (www.sec.gov). In this report, the term "Partnership," as well as the terms "ENLK," "our," "we," and "us" or like terms are sometimes used as 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 a direct, wholly-owned subsidiary of ENLC. ENLC's units are traded on the NYSE under the symbol "ENLC." ENLC's managing member is a wholly-owned subsidiary of GIP.

Devon Transaction

In 2014, we completed a series of transactions with Devon pursuant to which Devon contributed certain subsidiaries and assets to us in exchange for a majority interest in us (the "Devon Transaction").

GIP Transaction

On July 18, 2018, subsidiaries of Devon closed a transaction to sell all of their equity interests in ENLK, ENLC, and the managing member of ENLC to GIP. As a result of the transaction, GIP acquired control of (i) the managing member of ENLC, (ii) ENLC, and (iii) ENLK, as a result of ENLC's ownership of our general partner. See "Item 8. Financial Statements and Supplementary Data—Note 1" for more information on the GIP Transaction.

Simplification of the Corporate Structure

On January 25, 2019, we completed the Merger, an internal reorganization pursuant to which ENLC owns all of the outstanding common units of ENLK. As a result of the Merger:

- Each issued and outstanding ENLK common unit (except for ENLK common units held by ENLC and its subsidiaries) was converted into 1.15 ENLC common units, which resulted in ENLC owning all of the remaining outstanding ENLK common units.

- Our general partner's incentive distribution rights in ENLK were eliminated.

- Certain terms of the Series B Preferred Units were modified pursuant to an amended partnership agreement of ENLK. See "Item 8. Financial Statements and Supplementary Data—Note 8" for additional information regarding the modified terms of the Series B Preferred Units.

- ENLC issued to Enfield, the current holder of the Series B Preferred Units, for no additional consideration, ENLC Class C Common Units equal to the number of Series B Preferred Units held by Enfield immediately prior to the effective time of the Merger, in order to provide Enfield with certain voting rights with respect to ENLC. ENLC also agreed to issue an additional ENLC Class C Common Unit to the applicable holder of each Series B Preferred Unit for each additional Series B Preferred Unit issued by ENLK in quarterly in-kind distributions. In addition, for each Series B Preferred Unit that is exchanged into an ENLC common unit, an ENLC Class C Common Unit will be canceled.

- The Series C Preferred Units and all of our then-existing senior notes continue to be issued and outstanding following the Merger.

- Each unit-based award issued and outstanding immediately prior to the effective time of the Merger under the GP Plan was converted into 1.15 awards with respect to ENLC common units with substantially similar terms as were in effect immediately prior to the effective time.

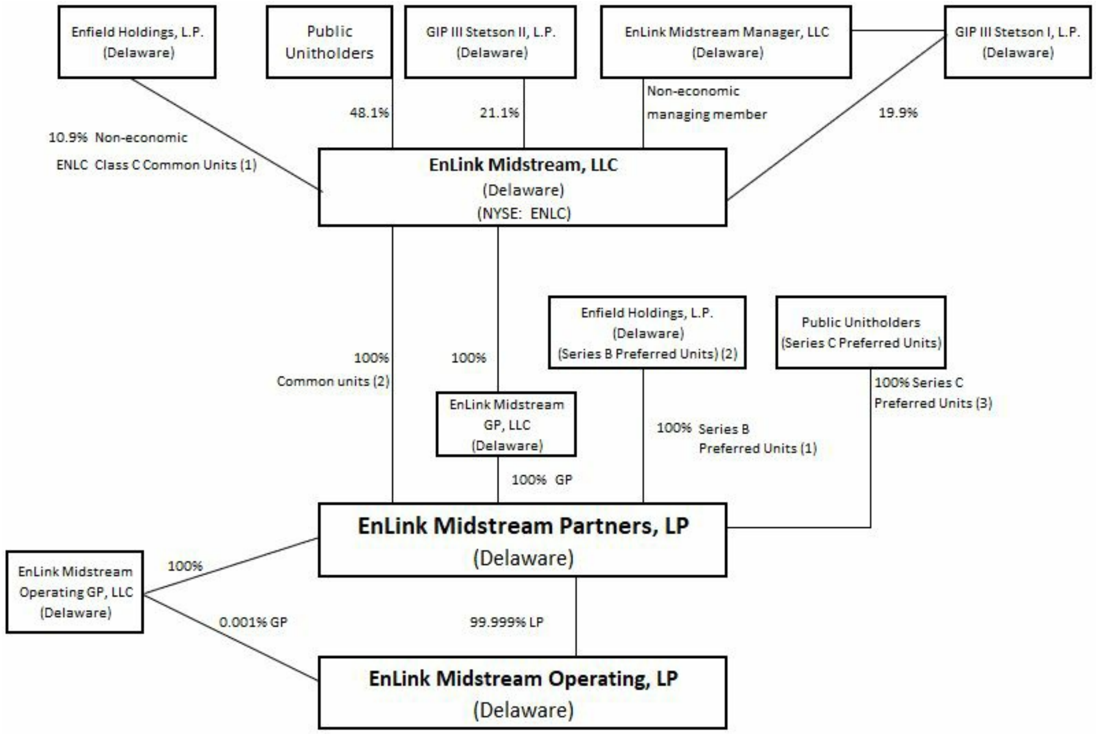
- Each unit-based award with performance-based vesting conditions issued and outstanding immediately prior to the effective time of the Merger under the GP Plan and the 2014 Plan was modified such that the performance metric for any then outstanding performance award relates (on a weighted average basis) to (i) the combined performance of ENLC and ENLK for periods preceding the effective time of the Merger and (ii) the performance of ENLC for periods on and after the effective time of the Merger.

- ENLC assumed the outstanding debt under the Term Loan and ENLK became a guarantor thereof. See "Item 8. Financial Statements and Supplementary Data—Note 6" for additional information regarding the Term Loan.

- We refinanced our existing revolving credit facilities at ENLK and ENLC. In connection with the Merger, ENLC entered into the Consolidated Credit Facility, with respect to which ENLK is a guarantor. See "Item 8. Financial Statements and Supplementary Data—Note 6" for additional information regarding the Consolidated Credit Facility.

For additional information on the organization of our business, see "Item 8. Financial Statements and Supplementary Data—Note 1."

The following diagram depicts our organization and ownership as of December 31, 2019:



(1) Series B Preferred Units are exchangeable into ENLC common units on a 1-for-1.15 basis, subject to certain adjustments. Upon the exchange of any Series B Preferred Units into ENLC common units, an equal number of the ENLC Class C Common Units will be canceled.
(2) All ENLK common units are held by ENLC. The Series B Preferred Units are entitled to vote, on a one-for-one basis (subject to certain adjustments) as a single class with ENLC, on all matters that require approval of the ENLK unitholders.
(3) Series C Preferred Units are perpetual preferred units that are not convertible into other equity interests, and therefore, are not factored into the ENLK 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, and selling NGLs; and
- gathering, transporting, stabilizing, storing, trans-loading, and selling crude oil and condensate, in addition to brine disposal services.

Our midstream energy asset network includes approximately 12,000 miles of pipelines, 21 natural gas processing plants with approximately 5.3 Bcf/d of processing capacity, seven fractionators with approximately 290,000 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.

Our natural gas business includes connecting the wells of producers in our market areas to our gathering systems. Our gathering systems consist of networks of pipelines that collect natural gas from points at or 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, marketers, 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. 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 the gathering and transmission of crude oil and condensate via pipelines, barges, rail, and trucks, in addition to condensate stabilization and brine disposal. We also purchase crude oil and condensate from producers and other supply sources and sell that crude oil and condensate through our terminal facilities to various markets.

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 most of our transactions is the use of our assets to transport a product or provide a processed product to an end-user or marketer at the tailgate of the plant, pipeline, barge, truck, or rail terminal.

Effective January 1, 2019, we changed our reportable operating segments to reflect how we currently make financial decisions and allocate resources. Prior to January 1, 2019, our reportable operating segments consisted of the following: (i) natural gas gathering, processing, transmission, and fractionation operations located in North Texas and the Permian Basin, primarily in West Texas, (ii) natural gas pipelines, processing plants, storage facilities, NGL pipelines, and fractionation assets in Louisiana, (iii) natural gas gathering and processing operations located throughout Oklahoma, and (iv) crude rail, truck, pipeline, and barge facilities in West Texas, South Texas, Louisiana, Oklahoma, and ORV. Effective January 1, 2019, we report our financial performance in five segments:

- *Permian Segment.* The Permian segment includes our natural gas gathering, processing, and transmission activities and our crude oil operations in the Midland and Delaware Basins in West Texas and Eastern New Mexico and our crude operations in South Texas;

- *North Texas Segment.* The North Texas segment includes our natural gas gathering, processing, and transmission activities in North Texas;

- *Oklahoma Segment.* The Oklahoma segment includes our natural gas gathering, processing, and transmission activities, and our crude oil operations in the Cana-Woodford, Arkoma-Woodford, northern Oklahoma Woodford, STACK, and CNOW shale 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 and our crude oil operations in ORV; and

- *Corporate Segment.* The Corporate segment includes our unconsolidated affiliate investments in the Cedar Cove JV in Oklahoma, our ownership interest in GCF in South Texas, our derivative activity, and our general corporate assets and expenses.

For more information about our segment reporting, see “Item 8. Financial Statements and Supplementary Data—Note 14.”

Our Business Strategies

We operate a differentiated midstream platform that is built for long-term, sustainable value creation. Our integrated assets are strategically located in premier production basins and core demand centers, including the Permian Basin, the Louisiana Gulf Coast, Central Oklahoma, and North Texas. 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:

- *Enhance the Profitability of Existing Business.* We are focused on enhancing the profitability of current operations and our strong, integrated base of assets by:
  - Filling available capacity of our assets and optimizing assets to support increasing demand.
  - Growing market share in areas across our footprint.
  - Reducing costs across our assets.
  - Capitalizing on opportunities to expand and capture business opportunities with customers.

- *Position to Capture Long-term Opportunities.* 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.

- *Optimize Strong Financial Position.* We are focused on strengthening our financial position by achieving long-term capital structure priorities, increasing cash flows, and maintaining balance sheet strength. 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.

- *Drive Organizational Efficiency.* We are committed to optimizing costs and efficiencies company-wide, while maintaining a high level of customer service and safety.

Recent Developments

Simplification of the Corporate Structure. On January 25, 2019, we completed the Merger, an internal reorganization pursuant to which ENLC owns all of the outstanding common units of ENLK. See "Item 8. Financial Statements and Supplementary Data—Note 1" for more information on the Merger and related transactions.

Transfer of EOGP Interest. On January 31, 2019, ENLC transferred its16.1% limited partner interest in EOGP to the Operating Partnership. See "Item 8. Financial Statements and Supplementary Data—Note 1" for more information regarding this transaction.

Organic Growth

Riptide Processing Plant. In September 2019, we completed construction of a 65 MMcf/d expansion to our Riptide processing plant in the Midland Basin, bringing the total operational processing capacity at the plant to 165 MMcf/d. We are currently in the process of further expanding our Riptide processing plant and expect an additional 55 MMcf/d of operational capacity to be completed during the fourth quarter of 2020.

Delaware Basin Processing Plant. In August 2019, we commenced construction of our Tiger Plant, which will expand our Delaware Basin processing capacity by an additional 200 MMcf/d. We expect the plant to be operational in the second half of 2020. This processing plant is owned by the Delaware Basin JV.

Central Oklahoma Plants. In June 2019, we commenced operations on our Thunderbird Plant, which expands our Central Oklahoma gas processing capacity by an additional 200 MMcf/d, bringing our total processing capacity at our Central Oklahoma facilities to 1.2 Bcf/d.

Cajun-Sibon Pipeline. In April 2019, we completed the expansion of our Cajun-Sibon NGL pipeline capacity, which connects the Mont Belvieu NGL hub to our fractionation facilities in Louisiana. This is the third phase of our Cajun-Sibon system referred to as Cajun Sibon III, which increases throughput capacity from 130,000 bbls/d to 185,000 bbls/d.

Lobo Natural Gas Gathering and Processing Facilities. In early April 2019, we completed construction of a 100 MMcf/d expansion to our Lobo III cryogenic gas processing plant, bringing the total operational processing capacity at our Lobo facilities to 375 MMcf/d.

Avenger Crude Oil Gathering System. Avenger is a crude oil gathering system in the northern Delaware Basin supported by a long-term contract with Devon on dedicated acreage in their Todd and Potato Basin development areas in Eddy and Lea counties in New Mexico. We commenced initial operations on Avenger during the third quarter of 2018 and began full-service operations during the second quarter of 2019.

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, 2019:

Gathering and Transmission Pipelines	Approximate Length (Miles)	Compression (HP)	Estimated Capacity (1)	Year Ended December 31, 2019 Average Throughput (2)
Gas Pipelines				
Permian assets:				
MEGA System gathering facilities	765	132,500	447	407,000
Lobo gathering system (3)	180	46,900	160	316,400
Permian gas assets (3)	945	179,400	607	723,400
North Texas assets:				
Bridgeport rich and lean gathering systems	2,800	206,700	900	762,700
Johnson County gathering system	390	49,000	400	111,700
Silver Creek gathering system	910	53,800	260	285,800
Acacia transmission system	130	16,000	920	491,700
North Texas gas assets	4,230	325,500	2,480	1,651,900
Oklahoma assets:				
Central Oklahoma gathering system	1,825	258,700	1,137	1,270,200
Northridge gathering system	140	14,000	65	32,000
Oklahoma gas assets	1,965	272,700	1,202	1,302,200
Louisiana assets:				
Louisiana gas gathering and transmission system	3,010	97,400	3,975	2,050,000
Total Gas Pipelines	10,150	875,000	8,264	5,727,500
NGL, Crude Oil, and Condensate Pipelines				
Permian assets:				
Victoria Express Pipeline	60	—	90,000	16,400
Permian Basin gathering (4)	455	—	238,500	115,600
Permian Crude Oil and Condensate assets	515	—	328,500	132,000
Oklahoma assets:				
Central Oklahoma crude oil gathering systems	175	—	160,000	47,300
Louisiana assets:				
Cajun-Sibon NGL pipeline system	760	—	185,000	164,200
Ascension NGL pipeline (5)	35	—	50,000	21,300
Ohio River Valley (6)	210	—	25,650	18,900
Louisiana NGL, Crude Oil, and Condensate assets	1,005	—	260,650	204,400
Total NGL, Crude Oil, and Condensate Pipelines	1,695	—	749,150	383,700

(1) Estimated capacity for gas pipelines is MMcf/d. Estimated capacity for liquids and crude and condensate pipelines is Bbls/d.
(2) Average throughput for gas pipelines is MMBtu/d. Average throughput for NGL, crude, and condensate pipelines is Bbls/d.
(3) 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.
(4) Estimated capacity is comprised of 188,500 Bbls/d of pipeline capacity and 50,000 Bbls/d of trucking capacity. Our Permian Basin gathering crude and condensate assets include the ECP system, Greater Chickadee system, and Avenger 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.

Processing Facilities	Processing Capacity (MMcf/d)	Year Ended December 31, 2019 Average Throughput (MMBtu/d)
Permian assets:		
MEGA system processing facilities	458	467,400
Lobo processing facilities	375	304,000
Permian assets	833	771,400
North Texas assets:		
Bridgeport processing facility	800	580,000
Silver Creek processing system (1)	480	170,500
North Texas assets	1,280	750,500
Oklahoma assets:		
Central Oklahoma processing facilities	1,245	1,181,900
Northridge processing facility	200	94,800
Oklahoma assets	1,445	1,276,700
Louisiana assets:		
Louisiana gas processing facilities (2)	1,778	400,200
Total Processing Facilities	5,336	3,198,800

(1) The Azle and Goforth processing plants are not operational. These plants represent 50 MMcf/d and 30 MMcf/d, respectively, of the total processing capacity of the Silver Creek processing system.
(2) The Blue Water, Eunice, and Sabine processing plants are not operational. These plants represent 193 MMcf/d, 350 MMcf/d, and 300 MMcf/d, respectively, of the total processing capacity of the Louisiana gas processing assets.

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Fractionation Facilities	Estimated NGL Fractionation Capacity (Bbls/d)	Year Ended December 31, 2019 Average Throughput (Bbls/d)
Permian assets:		
Mesquite terminal (1)	15,000	—
North Texas assets:		
Bridgeport processing facility (2)	15,000	—
Louisiana assets:		
Plaquemine fractionation facility (3)	125,000	79,200
Plaquemine processing plant	5,000	3,300
Eunice fractionation facility	70,000	58,700
Riverside fractionation facility (3)	—	33,600
Louisiana assets	200,000	174,800
Corporate assets:		
Gulf Coast Fractionators (4)	56,000	47,600
Total Fractionation Facilities	286,000	222,400

(1) The Mesquite terminal fractionator is not operational.
(2) Our Bridgeport processing plant in North Texas provides 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) 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 125 MBbls/d.
(4) Volumes shown reflect our 38.75% ownership in Gulf Coast Fractionators.

Storage Assets	Storage Type	Year Ended December 31, 2019 Estimated Storage Capacity (1)
Permian assets:		
Avenger storage	Crude	0.1
VEX storage	Crude	0.2
Oklahoma assets:		
Central Oklahoma storage	Crude	0.2
Louisiana assets:		
Belle Rose gas storage facility	Gas	11.9
Sorrento gas storage facility	Gas	7.3
Napoleonville NGL storage facility	NGL	6.0
ORV storage	Crude	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.

Permian Segment Assets. Our Permian segment assets include gas gathering systems, crude oil gathering systems and storage, gas processing facilities, and a fractionation facility, which assets are primarily in West Texas and New Mexico.

- Gas Gathering Systems. Our gas gathering systems are connected to our Permian Basin processing assets and consist of the following:

  - *MEGA system gathering facilities*. This gathering system in the Midland 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.* This rich natural gas gathering system consists of gathering pipeline and compression assets in the Delaware Basin in Texas and New Mexico. The Lobo gathering system is owned by the Delaware Basin JV.

- Crude Oil Gathering Systems. Our crude oil gathering systems consist of crude oil and condensate pipelines and above ground storage, including:

  - *Avenger.* During 2018, we constructed a new crude oil gathering system in the northern Delaware Basin called Avenger. Avenger is supported by a long-term contract with Devon on dedicated acreage in their Todd and Potato Basin development areas in Eddy and Lea counties in New Mexico. We commenced initial operations on Avenger during the third quarter of 2018 and full-service operations during the second quarter of 2019.

  - *Greater Chickadee Gathering System.* Greater Chickadee 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.

  - *VEX.* VEX includes a multi-grade crude oil pipeline with terminals in Cuero and the Port of Victoria and barge docks. The Cuero truck unloading terminal at the origin of the VEX system contains 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 unloading dock and above-ground storage capacity. The Port of Victoria Terminal delivers to two barge loading docks at the Port of Victoria.

  - *ECP System.* The ECP System includes trucking and crude gathering pipelines in the Midland Basin.

- Gas Processing Facilities. Our Permian Basin gas processing facilities include six gas processing plants and consist of the following:

  - *MEGA system processing facilities.* Our MEGA system natural gas processing facilities 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 160 MMcf/d, and the Riptide processing facility with a capacity of 165 MMcf/d.

  - *Lobo processing facilities*. Our Lobo natural gas processing facilities are located in Loving County, Texas and include Lobo I, Lobo II, and Lobo III, which account for 35 MMcf/d, 140 MMcf/d, and 200 MMcf/d of processing capacity, respectively. The Lobo processing facilities and the connected gathering system are owned by the Delaware Basin JV.

- Fractionation Facility. The Mesquite fractionator has an approximate capacity of 15,000 Bbls/d and is located at our Midland gas processing plant complex. We idled the Mesquite fractionator and only operate the condensate stabilizer in the Mesquite terminal, which has a capacity of 5,000 Bbls/d.

North Texas Segment Assets. Our North Texas segment assets include gas gathering systems, a gas transmission system, gas processing facilities, and a fractionation facility in the Barnett Shale.

- Gas Gathering Systems. Our gas gathering systems are connected to our processing assets and consist of the following:

  - *Bridgeport rich gas 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 gas gathering system contributing substantially all of the natural gas gathered for the year ended December 31, 2019. As described above, we have extended our fixed-fee gathering agreement with Devon, which was effective after the GIP Transaction, and currently have approximately nine years remaining on a fixed-fee gathering agreement with Devon pursuant to which we provide gathering services on the Bridgeport system.

  - *Bridgeport lean gas gathering system.* Natural gas gathered on the Bridgeport lean gas gathering system is primarily 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 one customer with whom we have a fixed-fee processing agreement that currently has approximately four years remaining.

  - *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.

- Gas 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 largest customer on the Acacia pipeline with approximately four years remaining on a fixed-fee transportation agreement that covers transmission services and includes annual rate escalators.

- Gas Processing Facilities. Our gas processing facilities in North Texas include four gas processing plants and consist of 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, 2019. We have extended our fixed-fee processing agreement with Devon, which was effective after the GIP Transaction, and currently have approximately nine years remaining on our agreement with Devon pursuant to which we provide processing services for natural gas delivered by Devon to the Bridgeport processing facility.

  - *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, 400 MMcf/d, and 30 MMcf/d of processing capacity, respectively. During 2018, we idled the Azle and Goforth plants due to decreased volumes. Currently, the processing capacity at the Silver Creek plant is sufficient to process all gas on the Silver Creek processing system.

- Fractionation Facility. Our Bridgeport processing plant in North Texas also has fractionation capabilities that provide operational flexibility for the related processing plants but is not the primary fractionation facility for the NGLs produced by the processing plants. Under our current contracts, we do not earn fractionation fees for operating this facility, so throughput volumes through this facility are not captured on a routine basis and are not significant to our gross operating margin.

Oklahoma Segment Assets. Our Oklahoma segment assets consist of gas processing facilities, gas gathering systems, and crude oil gathering systems and storage in Southern and Central Oklahoma.

- Gas Gathering Systems. Our Oklahoma gas gathering systems consist of the following:
  - *Central Oklahoma gathering system.* The Central Oklahoma gathering system serves the STACK and CNOW plays. In addition, our contractual arrangement with Devon includes an MVC that will remain in effect until December 2020. For 2020, the MVC dictates that approximately 230 MMcf/d of natural gas will be delivered through the Chisholm gathering system.
  - *Northridge gathering system.* Our Northridge gathering system is located in the Arkoma-Woodford Shale in Southeastern Oklahoma.
- Gas Processing Facilities. Our gas processing facilities consist of the following:
  - *Central Oklahoma processing facilities.* The Central Oklahoma processing facilities include the Thunderbird Plant, the Chisholm plants, the Battle Ridge plant, and the Cana processing facilities (collectively, the "Central Oklahoma processing system"), which account for 200 MMcf/d, 560 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, LP and an affiliate of ONEOK, Inc. ("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. We have extended our fixed-fee processing agreement with Devon, which was effective after the GIP Transaction, and currently have approximately nine 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. Additionally, we have a contractual arrangement with Devon on the Chisholm plants that includes an MVC that will remain in effect until December 2020. For 2020, the MVC dictates that approximately 230 MMcf/d of natural gas will be delivered to the Chisholm plant 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 Energy, Inc., Enable Midstream Partners, LP, and MPLX LP.
- Crude Oil Gathering Systems. Our Oklahoma crude and condensate assets have crude oil and condensate pipelines and above ground storage in Central Oklahoma. These assets consist of the following:
  - *Central Oklahoma Crude Oil Gathering Systems.* Our Central Oklahoma crude oil gathering systems include Black Coyote and Redbud. Black Coyote operates in the core of the STACK play in Central Oklahoma and was built primarily to service acreage dedicated from Devon, which is the anchor customer on the system. Redbud also operates in the core of the STACK play and is supported by a contract with Marathon Oil Company.

Louisiana Segment Assets. Our Louisiana segment assets consist of gas and NGL gathering and transmission pipelines, gas processing facilities, gas and NGL storage, and our ORV crude logistics assets.

- Transmission and Gathering 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, Louisiana and New Orleans, Louisiana. 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 six gas processing plants, of which three are currently operational, and two storage facilities. These assets consist of the following:

  - *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 Gibson 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.

  - *Belle Rose Gas Storage Facility.* The Belle Rose 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.

  - *Sorrento Gas Storage Facility.* The Sorrento gas 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.

  - *Idled Processing Plants:*

    - *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. We have shut down the Blue Water gas processing plant and we do not expect to operate it in the near future unless 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 350 MMcf/d of natural gas. We have shut down the Eunice processing plant. The plant is not expected to operate in the near future unless volumes are sufficient to run the plant.

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

- NGL and Crude Oil Pipeline Systems. Our NGL and crude oil pipeline systems consist of NGL pipelines, crude oil and condensate pipelines, underground NGL storage, and our ORV crude logistics assets.

  - *Cajun-Sibon Pipeline System.* The Cajun-Sibon pipeline system transports unfractionated NGLs from areas such as the Liberty, Texas interconnects near Mont Belvieu, Texas, and, from time to time, our Gibson and Pelican processing plants in South Louisiana to either the Plaquemine 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 Corporation’s Garyville refinery and is owned 50% by Marathon Petroleum Corporation.

  - *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.

- *Napoleonville Storage Facility*. The Napoleonville NGL storage facility is connected to the Riverside facility and is comprised of two existing caverns. The caverns currently provide butane storage.

- Fractionation Facilities. There are four fractionation facilities located in Louisiana that are connected to our processing facilities and to Mont Belvieu, Texas 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 125,000 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 system. The Eunice fractionation facility fractionates butane and heavier products from our Riverside facility and is directly connected to NGL markets and to a third-party storage facility.

  - *Riverside Fractionation Facility.* The Riverside fractionator and loading facility are located on the Mississippi River upriver from Geismar, Louisiana. Liquids are delivered to the Riverside fractionator by pipeline from the 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.

Corporate Segment Assets. Our Corporate segment assets primarily consist of our 38.75% ownership interest in GCF and 30% ownership interest in the Cedar Cove JV.

- *GCF*. We own a 38.75% interest in GCF, with the remaining interests owned 22.5% by Phillips 66, and 38.75% by Targa Resources Partners, LP. 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 customers for a fee.

- *Cedar Cove JV.* We own a 30% interest in the Cedar Cove JV, which operates gathering and compression assets in Blaine County, Oklahoma that tie into our existing Oklahoma assets. Kinder Morgan, Inc. owns a 70% interest in, and is the operator of, the Cedar Cove JV. All gas gathered by the Cedar Cove JV is processed by our Central Oklahoma processing facilities.

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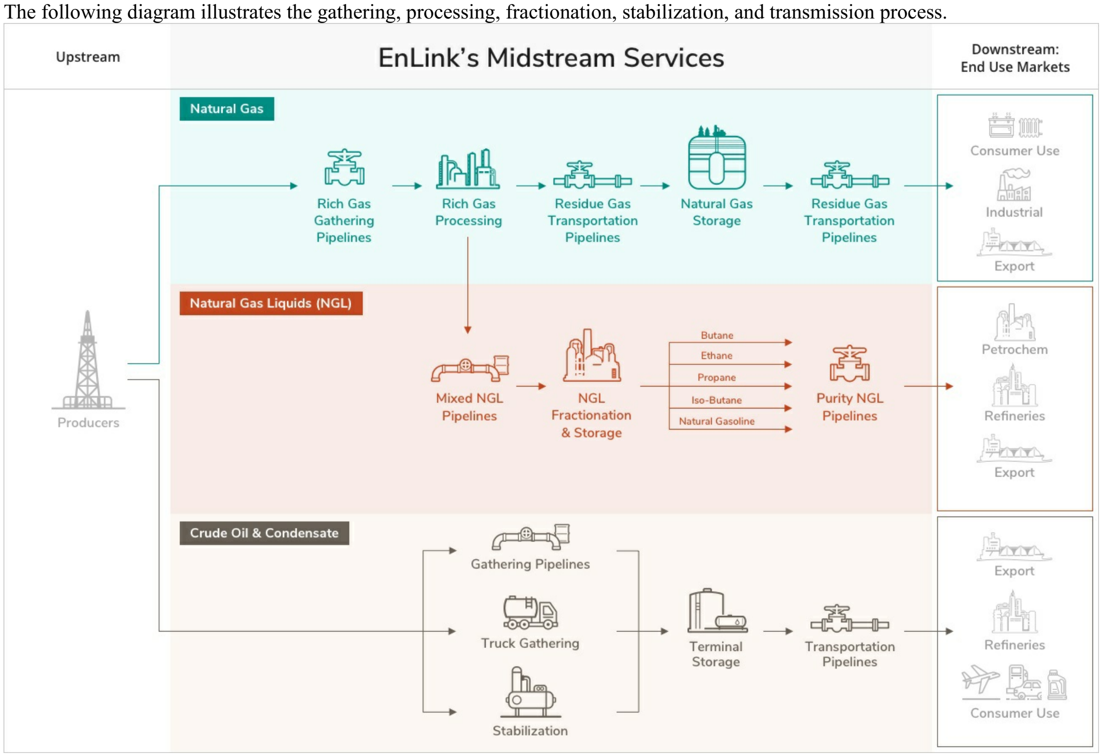
Industry Overview

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, NGLs, 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 to balance our margin position. 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, NGL, or crude oil 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, transportation, and processing 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 compete with similar enterprises in providing additional gathering and processing services in its respective areas of operation. Many of our competitors may offer more services or have stronger 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.

The following customers individually represented greater than 10% of our consolidated revenues. These customers represent a significant percentage of revenues, and the loss of the customer would have a material adverse impact on our results of operations because the revenues and gross operating margin received from transactions with these customers is material to us. No other customers represented greater than 10% of our consolidated revenues.

	Year Ended December 31,		
	2019	2018	2017
Devon	10.5%	10.4%	14.4%
Dow Hydrocarbons and Resources LLC	10.0%	11.1%	11.2%
Marathon Petroleum Corporation	13.8%	11.5%	(1)

(1) Consolidated revenues for Marathon Petroleum Corporation did not exceed 10% of our consolidated revenues for the year ended December 31, 2017.

Regulation

Natural Gas Pipeline Regulation. We own an interstate natural gas pipeline that is subject to regulation as a natural gas company by the 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 of service for our interstate pipeline services regulated by FERC must be just and reasonable and not unduly preferential or unduly discriminatory, although negotiated rates may be accepted in certain circumstances. Such rates and terms and conditions of service are set forth in FERC-approved tariffs. Proposed rate increases and changes to our tariff 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 cost-of-service rates charged by our FERC regulated natural gas pipeline may also be affected by FERC's income tax allowance policy, although we do not currently expect to experience any impact to financial results as a result of this 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 SFPP, L.P., then an interstate petroleum products pipeline organized as a master 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. In March 2018, FERC issued an Order on Remand to SFPP, L.P. and simultaneously issued a revised policy statement disallowing master limited partnerships from recovering both an income tax allowance for the partners' tax costs and a discounted cash flow return on equity in their cost-of-service rates. The revised policy statement further provides that FERC will address the application of this policy to partnerships and pass-through entities that are not organized as master limited partnerships in subsequent proceedings on a case-by-case basis as the issue arises. In July 2018, FERC dismissed the requests for rehearing of the revised policy statement and provided guidance that if a pipeline organized as a master limited partnership or other pass-through entity eliminates its income tax allowance from its cost of service, FERC anticipates that such pipeline will also remove accumulated deferred income taxes from its cost of service. FERC further required all interstate natural gas pipelines to file a one-time informational filing in 2018 on a new form in order to collect information to evaluate the impact of the 2017 Tax Cuts and Jobs Act and the revised policy statement on such pipelines.

In addition to policies regarding rate setting, 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 if such marketing affiliates are shippers on their interstate natural gas pipelines. 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 approximately $1.3 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 cost-of-service rates charged by our interstate liquids pipelines may also be affected by FERC's revised income tax allowance policy statement discussed above. In addition, FERC intends to incorporate its revised income tax allowance policy as well as the impact of the tax reduction from the Tax Cuts and Jobs Act of 2017 in its next five-year review of the oil pipeline index, which is scheduled to occur in 2020 to establish the index level for the July 1, 2021 to June 30, 2026 time period.

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. On January 13, 2020, PHMSA transmitted a final rule to the Office of the Federal Register for publication. This final rule has not yet been published or made available for public review. However, PHMSA has issued statements indicating that the final rule will be consistent with the December 2016 IFR. 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.

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.

In July 2018, PHMSA issued an advance notice of proposed rulemaking seeking comment on the class location requirements for natural gas transmission pipelines, and particularly the actions operators must take when class locations change due to population growth or building construction near the pipeline.

In October 2019, PHMSA issued three new final rules. One rule establishes procedures to implement the expanded emergency order enforcement authority set forth in an October 2016 interim final rule. Among other things, this rule allows PHMSA to issue an emergency order without advance notice or opportunity for a hearing. The other two rules impose several new requirements on operators of onshore gas transmission systems and hazardous liquids pipelines. The rule concerning gas transmission extends the requirement to conduct integrity assessments beyond HCAs to pipelines in Moderate Consequence Areas (“MCAs”). It also includes requirements to reconfirm Maximum Allowable Operating Pressure (“MAOP”), report MAOP exceedances, consider seismicity as a risk factor in integrity management, and use certain safety features on in-line inspection equipment. The rule concerning hazardous liquids extends the required use of leak detection systems beyond HCAs to all regulated non-gathering hazardous liquid pipelines, requires reporting for gravity fed lines and unregulated gathering lines, requires periodic inspection of all lines not in HCAs, calls for inspections of lines after extreme weather events, and adds a requirement to make all lines in or affecting HCAs capable of accommodating in-line inspection tools over the next 20 years.

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.

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. 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 (“DFW area”) for the 2008 revised ozone national ambient air quality standard (“NAAQS”). Effective September 23, 2019, the DFW area was reclassified to a serious nonattainment area under this standard, potentially requiring the state to adopt more stringent permitting requirements. Under the area’s serious nonattainment designation, new major sources in Wise County, meaning sources that emit greater than 50 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 25 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 1.2 to 1 ratio.

In October 2015, the EPA promulgated a new NAAQS for ozone of 70 parts per billion (“ppb”) for both the 8-hour primary and secondary standards, down from the 75 ppb standards of the 2008 ozone NAAQS. On June 4, 2018, EPA designated the DFW area, including Wise County, as a marginal nonattainment area under this standard. EPA published a final rule to implement the 2015 ozone NAAQS on December 6, 2018. The area’s marginal classification does not require the additional control measures to be implemented. However, should the area fail to attain this standard by its marginal attainment date of August 2021, it risks reclassification to moderate, which 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. Furthermore, the area remains subject to the requirements associated with its serious classification under the 2008 standard notwithstanding its marginal classification under the 2015 standard. 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.

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 under the NSPS. In October 2018, and pursuant to its reconsideration, the EPA proposed a rule that would amend certain requirements of the NSPS standard. In August 2019, EPA published a rule proposing to reconsider certain aspects of both the 2012 and 2016 rules. This proposed rule would remove sources in the transmission and storage segments from the regulated source category and would rescind the application of the NSPS and methane-specific requirements to these sources. The rule remains in effect pending reconsideration. 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 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. EPA draft guidance issued in September 2018 clarified that this rule pertains to the oil and gas industry.

Other federal agencies have also taken steps to impose 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 the effective date of others was delayed until 2019 pending reconsideration. In September 2018, BLM published a final rule that rescinded several requirements of the 2016 methane rules. The September 2018 rule was challenged in the U.S. District Court for the Northern District of California almost immediately after issuance. The challenge is still pending. 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.

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 November 2019, the State Department formally informed the United Nations of the United States' withdrawal from the Paris Agreement. Due to the Paris Agreement's protocol, the withdrawal will be effective in November 2020. There are no guarantees that the agreement will not be re-implemented in the U.S., or re-implemented in part by specific U.S. states or local governments. 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 ("USACE") finalized a rule intended to clarify the meaning of the term "waters of the United States," ("WOTUS") which establishes the scope of regulated waters under the Clean Water Act. The rule has been challenged and was stayed by federal courts. If upheld, the rule is expected to expand federal jurisdiction under the Clean Water Act. On February 6, 2018, EPA and

USACE published a final rule to postpone the effectiveness of the WOTUS rule until February 6, 2020. The February 2018 delay rule is subject to pending judicial challenges in multiple federal district courts. In October 2019, EPA and USACE issued a final rule that repealed the 2015 WOTUS definition and reinstated the agencies' narrower pre-2015 scope of federal CWA jurisdiction. In January 2020, EPA and USACE promulgated a new WOTUS definition that continues to provide a narrower scope of federal CWA jurisdiction than contemplated under the 2015 WOTUS definition, while also providing for greater predictability and consistency of federal CWA jurisdiction. Judicial challenges to EPA's October 2019 final rule to repeal the 2015 WOTUS definition are currently before multiple federal district courts and challenges to EPA's January 2020 rule are anticipated. If the October 2019 final rule is vacated and the expanded scope of jurisdiction in the 2015 rule is ultimately implemented, or to the extent that any future rules expand the scope of the Clean Water Act's jurisdiction, we could face increased costs and delays with respect to obtaining permits for activities in jurisdictional waters, including wetlands. 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.

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 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. Such regulations could also affect our customers' injection well operations and, therefore, impact our gathering business.

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. 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. A federal district court invalidated these BLM rules in June 2016, but they were reinstated on appeal by the U.S. Court of Appeals for the Tenth Circuit in September 2017. In December 2017, BLM published a final rule rescinding the 2015 BLM rules. This rescission is subject to pending challenges in federal courts. Reinstatement of the 2015 BLM rules, or the adoption of 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, 32,000 square feet in Houston, Texas under long-term leases, and various other locations to support our operations.

Employees

As of December 31, 2019, we (through our subsidiaries) employed 1,355 full-time employees. Of these employees, 296 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 unitholders and noteholders) could be affected materially and adversely. Readers are advised to refer to the context in which terms are used, and to read these risk factors in conjunction with other detailed information concerning our business as 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.

Risks Inherent in our Business

We are dependent on Devon for a substantial portion of the natural gas that we gather, process, and transport. The expiration of a five-year MVC from Devon in December 2020 will result in a 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 2019 have been below the MVC levels under this contract.

We are dependent on Devon for a substantial portion of our natural gas supply. For the year ended December 31, 2019, Devon represented approximately 29.9% of our gross operating margin. In order to minimize volumetric exposure, we entered into an agreement providing a five-year MVC from Devon at the Chisholm processing facility and gathering system, which expires in December 2020. For the year ended December 31, 2019, we recognized $10.3 million in MVC shortfall revenue from Devon attributable to this MVC agreement because volumes were below the minimum level. In 2020, this expiring MVC agreement is projected to generate approximately $55-$65 million of shortfall revenue. In 2021, if volumes under the MVC agreement do not increase or we are unable to replace the shortfall revenue from other sources, our operating results and cash flows would be adversely affected.

Because we are substantially dependent on Devon for a significant portion of our gross operating margin, any development that materially and adversely affects their operations, financial condition, or market reputation could have a material and adverse impact on us. Material adverse changes for Devon could restrict our access to capital, make it more expensive to access the capital markets, or increase the costs of our borrowings.

We expect to derive a significant portion of our gross operating margin from Devon for the foreseeable future. As a result, any development, whether in our area of operations or otherwise, that adversely affects their 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 our significant customers, 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 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 dependence on 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 limiting 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.

Adverse developments in our gathering, transmission, processing, crude oil, condensate, natural gas, and NGL services businesses would adversely affect our financial condition and results of operations, and 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.

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. In recent periods, we have seen suppressed drilling activity due to low commodity prices, which has resulted in lower volumes in some of the basins in which we operate. 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, exploration and production industry may negatively impact current and future drilling activity. In addition, real or perceived differences in economic returns from various producing basins could influence producers to direct their future drilling activity away from basins in which we currently operate. 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:

- continued fluctuations in commodity prices, including the prices of natural gas, NGLs, crude oil, and condensate;
- 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;
- 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. We have recognized goodwill impairments and impairments on property and equipment in the past, including the $190.3 million of goodwill impairments taken during 2019. See “Item 8. Financial Statements and Supplementary Data—Note 3” for more information about impairment of goodwill and long-lived assets. Additional impairment of the value of our existing goodwill and long-lived 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.

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 and results of operations.

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. The EPA announced its intention to reconsider the regulations relating to the capture of air emissions in April 2017 and sought to stay its requirements, however, EPA's stay of these requirements was vacated by the D.C. Circuit in July 2017. In August 2019, EPA published a rule proposing to reconsider certain aspects of both the 2012 and 2016 rules. This proposed rule would remove sources in the transmission and storage segments from the regulated source category and would rescind the application of the NSPS and methane-specific requirements to these sources. However, the rule remains in effect pending reconsideration, 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. In September 2018, BLM published a final rule that repealed several of the requirements of the 2016 methane rule. The September 2018 rule was challenged in the U.S. District Court for the Northern District of California almost immediately after issuance. The challenge is still pending.

In addition, certain candidates in the 2020 U.S. presidential campaign have declared that they would support federal government efforts to limit or prohibit hydraulic fracturing. These declarations include threats to take actions banning hydraulic fracturing of crude oil and natural gas wells and banning new leases for production of minerals on federal properties, including onshore lands and offshore waters. A new presidential administration could also pursue the imposition of more restrictive requirements for the establishment of pipeline infrastructure or the permitting of LNG export facilities.

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 brine disposal operations and our customers' injection well operations, which could impact our gathering business.

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

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. In November 2019, the State Department formally informed the United Nations of the United States' withdrawal from the Paris Agreement. Due to the Paris Agreement's protocol, the withdrawal will be effective in November 2020. There are no guarantees that the agreement will not be re-implemented in the U.S. or re-implemented in part by specific U.S. states or local governments. 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.

Governmental, scientific and public concern over the threat of climate change arising from GHG emissions has resulted in increasing political risks in the U.S., including climate change related pledges made by certain candidates in the U.S. presidential campaign. These pledges include threats to take actions banning hydraulic fracturing of crude oil and natural gas wells and banning new leases for production of minerals on federal properties, including onshore lands and offshore waters. A new presidential administration could also pursue the imposition of more restrictive requirements for the establishment of pipeline infrastructure or the permitting of LNG export facilities.

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.

In addition to the regulatory efforts described above, there have also been efforts in recent years aimed at the investment community, including investment advisors, sovereign wealth funds, public pension funds, universities, and other groups, promoting the divestment of fossil fuel equities as well as pressuring lenders and other financial services companies to limit or curtail activities with fossil fuel companies. These efforts could have a material adverse effect on the price of our securities and our ability to access equity capital markets. Members of the investment community have begun to screen companies such as ours for sustainability performance, including practices related to GHGs and climate change, before investing in our securities. In addition, discussions of GHG emissions and their possible impacts have become more widespread generally in society and public sentiment regarding these topics may become more challenging for fossil fuel companies. As a result, we could experience additional costs or financial penalties, delayed or cancelled projects, and/or reduced production and reduced demand for hydrocarbons, which could have a material adverse effect on our earnings, cash flows and financial condition.

Although it is not possible at this time to predict whether future legislation or new regulations may be adopted to address GHG 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 or crude oil we gather, process, or otherwise handle in connection with our services.

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, increase 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. Fitch Ratings, S&P, and Moody's have currently assigned a BBB-, BB+, and Ba1 credit rating, respectively, to ENLK and ENLC. In August 2019, Fitch Ratings announced that it had revised its rating outlook for both ENLK and ENLC to negative from stable. Any downgrade could also lead to higher borrowing costs for future borrowings and 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. 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 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 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, crude oil, and condensate sales commitments that we satisfy through supplies purchased under long-term gas, NGL, crude oil, 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.

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, 2019, approximately 7% 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 endedDecember 31, 2019, less than 1% 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 the levels of volumes we transport 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, 2019, gross operating margin realized associated with product upgrades represented less than 1% of our gross operating margin.

Commodity prices were volatile during 2019 and the prices for natural gas and natural gas products declined Crude oil prices increased 31% while weighted average NGL prices and natural gas prices decreased 25% and 26%, respectively, from January 1, 2019 to December 31, 2019. In February 2020, natural gas prices reached a low of $1.77 per MMBtu, which was the lowest price since March 2016. 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 2019 ranged from a high of $66.30 per Bbl in April 2019 to a low of $46.54 per Bbl in January 2019. Weighted average NGL prices in 2019 (based on the Oil Price Information Service ("OPIS") Napoleonville daily average spot liquids prices) ranged from a high of $0.56 per gallon in February 2019 to a low of $0.25 per gallon in July 2019. Natural gas prices (based on Gas Daily Henry Hub closing prices) during 2019 ranged from a high of $3.59 per MMBtu in January 2019 to a low of $2.07 per MMBtu in August 2019.

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;
- public health crises that reduce economic activity and affect the demand for travel, including the coronavirus outbreak;
- the availability of local, intrastate, and interstate transportation systems;
- the availability of downstream NGL fractionation facilities;
- the availability and marketing of competitive fuels;
- the development and adoption of alternative energy technologies, such as electric vehicles;
- 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 the Consolidated Credit Facility and the Term Loan 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 and future business opportunities 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 undertake any of these actions on satisfactory terms or at all.

The terms of the Consolidated Credit Facility, Term Loan, and indentures governingENLC's senior notes and oursenior notes may restrict our current and future operations, particularly our ability to respond to changes in business or to take certain actions.

The Consolidated Credit Facility, the Term Loan, and the indentures governing ENLC's senior notes and oursenior 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, the Consolidated Credit Facility and the Term Loan require ENLC to satisfy and maintain specified financial ratios. ENLC's ability to meet these financial ratios can be affected by events beyond its control, and we cannot assure you that ENLC will continue to meet these ratios.

Our ability to comply with the covenants and restrictions contained in the Consolidated Credit Facility, the Term Loan, andENLC's and our 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 the Consolidated Credit Facility, the Term Loan, and ENLC's and our 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 the Consolidated Credit Facility, the Term Loan, or ENLC's and our 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.

Changes in the method of determining the London Interbank Offered Rate, or the replacement of the London Interbank Offered Rate with an alternative reference rate, may adversely affect interest expense related to outstanding debt.

Amounts drawn under the Consolidated Credit Facility and the Term Loan currently bear interest at rates based on the London Interbank Offered Rate ("LIBOR"). Interest charged to ENLK for borrowings made through the related party debt arrangement are substantially the same as interest charged to ENLC on borrowings under the Consolidated Credit Facility and the Term Loan. On July 27, 2017, the Financial Conduct Authority in the United Kingdom announced that it would phase out

LIBOR as a benchmark by the end of 2021. It is unclear whether new methods of calculating LIBOR will be established such that it continues to exist after 2021. The Consolidated Credit Facility and the Term Loan include a mechanism to amend the facilities to reflect the establishment of an alternative rate of interest upon the occurrence of certain events related to the phase-out of LIBOR. However, we have not yet pursued any technical amendment or other contractual alternative to address this matter and are currently evaluating the impact of the potential replacement of LIBOR. If no such amendment or other contractual alternative is established on or prior to the phase-out of LIBOR, interest under the Consolidated Credit Facility and Term Loan will bear interest at higher rates based on the prime rate until such amendment or other contractual amendment is established. Even where we have entered into interest rate swaps or other derivative instruments for purposes of managing our interest rate exposure, our hedging strategies may not be effective as a result of the replacement or phasing out of LIBOR, and our earnings may be subject to volatility. In addition, the overall financial markets may be disrupted as a result of the phase-out or replacement of LIBOR. The potential increase in our interest expense as a result of the phase-out of LIBOR and uncertainty as to the nature of such potential phase-out and alternative reference rates or disruption in the financial market could have an adverse effect on our financial condition, results of operations and cash flows.

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 unitholders 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 all of the land on which our pipelines, compression, and plant facilities are located, which could disrupt our operations.

We do not own all 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. 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. In late May 2019, White Star, the counterparty to our $58.0 million second lien secured term loan receivable, filed for reorganization under Chapter 11 of the U.S. Bankruptcy Code and was not able to repay the outstanding amounts owed to us under the second lien secured term loan. For additional information regarding this transaction, refer to “Item 8. Financial Statements and Supplementary Information—Note 2.”

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.

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 approximately $1.3 million per day 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, FERC’s current income tax allowance policy could affect our rates going forward, although we do not currently expect to experience any impact to financial results as a result of this policy. In addition, our rates going forward could be affected by proposed changes to FERC’s annual indexing methodology, including both changes to the methodology to account for the impact of the tax reduction from the Tax Cuts and Jobs Act of 2017 as well as the potential 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 these FERC policies and potential changes could have a material impact on our business and, 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. In October 2019, PHMSA issued three new final rules. One rule establishes procedures to implement the expanded emergency order enforcement authority set forth in an October 2016 interim final rule. Among other things, this rule allows PHMSA to issue an emergency order without advance notice or opportunity for a hearing. The other two rules impose several new requirements on operators of onshore gas transmission systems and hazardous liquids pipelines. The rule concerning gas transmission extends the requirement to conduct integrity assessments beyond HCAs to pipelines in MCAs. It also includes requirements to reconfirm MAOP, report MAOP exceedances, consider seismicity as a risk factor in integrity management, and use certain safety features on in-line inspection equipment. The rule concerning hazardous liquids extends the required use of leak detection systems beyond HCAs to all regulated non-gathering hazardous liquid pipelines, requires reporting for gravity fed lines and unregulated gathering lines, requires periodic inspection of all lines not in HCAs, calls for inspections of lines after extreme weather events, and adds a requirement to make all lines in or affecting HCAs capable of accommodating in-line inspection tools over the next 20 years. 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 $3.1 million, $1.8 million, and $2.3 million for the years ended December 31, 2019, 2018, and 2017, 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. In August 2019, EPA published a rule proposing to reconsider certain aspects of the 2016 rule. This proposed rule would remove sources in the transmission and storage segments from the regulated source category and would rescind the application of the NSPS and methane-specific requirements to these sources. The rule remains in effect pending reconsideration. 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.

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. In September 2018, BLM published a final rule to repeal certain requirements of the 2016 methane rule. The September 2018 rule was challenged in the U.S. District Court for the Northern District of California almost immediately after issuance. The challenge is still pending.

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.

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 relevant regulations, and other rulemakings are pending at the CFTC, the product of which would be rules that implement the mandates in the 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 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. The CFTC proposed new rules in January 2020 (withdrawing previously proposed rules from November 2013 and December 2016) 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 sought comment on the position limits rules as reproposed and revised, but the new rules have not yet been issued in final form, and the impact of any final provisions on us is uncertain at this time.

The legislation and potential 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 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 the Consolidated Credit Facility and the Term Loan expose 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 volatility in commodity prices. As of December 31, 2019, 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.

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, 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. In addition, our counterparty in any hedging transaction could default on its obligation to pay or otherwise fail to perform. 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 cyberattack 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, plants, truck fleet, and other 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 “cyberattacks” on businesses to disable or disrupt computer systems, disrupt operations, and steal funds or data including through so-called “phishing” schemes. Cyberattacks 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 assets 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 cyberattacks than other targets in the United States. Our insurance may not protect us against such occurrences. Any such terrorist or cyberattack 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 cyberattacks continue to evolve, we may be required to expend significant additional resources to further enhance our digital security or to remediate vulnerabilities. In addition, cyberattacks 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 business is subject to complex and evolving U.S. laws and regulations regarding privacy and data protection (“data protection laws”). Many of these laws and regulations are subject to change and uncertain interpretation, and could result in claims, increased cost of operations, or otherwise harm our business.

The regulatory environment surrounding data privacy and protection is constantly evolving and can be subject to significant change. New data protection laws pose increasingly complex compliance challenges and potentially elevate our costs. Complying with varying jurisdictional requirements could increase the costs and complexity of compliance, and violations of applicable data protection laws can result in significant penalties. Any failure, or perceived failure, by us to comply with applicable data protection laws could result in proceedings or actions against us by governmental entities or others, subject us to significant fines, penalties, judgments, and negative publicity, require us to change our business practices, increase the costs and complexity of compliance, and adversely affect our business. As noted above, we are also subject to the possibility of cyberattacks, which themselves may result in a violation of these laws. Additionally, if we acquire a company that has violated or is not in compliance with applicable data protection laws, we may incur significant liabilities and penalties as a result.

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 the Operating Partnership 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.

Risks Inherent in an Investment in the Partnership

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

GIP, 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. Conflicts of interest may arise in the future among GIP and its affiliates, including our general partner, on the one hand, and our partnership and our unitholders, on the other hand. In resolving these conflicts of interest, our general partner may favor its own interests and those of its affiliates, including GIP and ENLC, over our interests. Subject to certain limitations, 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.

GIP is not limited in its ability to compete with us and is not obligated to offer us the opportunity to acquire additional assets or businesses, which could limit our ability to grow and could adversely affect our results of operations and cash available for distribution to our unitholders.

GIP is a private equity firm with significant resources and experience making investments in midstream energy businesses. GIP is not prohibited from owning assets or interests in entities, or engaging in businesses, that compete directly or indirectly with us. Affiliates of GIP currently own interests in other oil and gas companies, including midstream companies, which may compete directly or indirectly with us. In addition, GIP and its affiliates may acquire, construct, or dispose of additional midstream or other assets and may be presented with new business opportunities, without any obligation to offer us the opportunity to purchase or construct such assets or to engage in such business opportunities.

Pursuant to the terms of our partnership agreement, the doctrine of corporate opportunity, or any analogous doctrine, does not apply to our general partner, its executive officers, or any of its affiliates, including GIP. Any such person or entity that becomes aware of a potential transaction, agreement, arrangement or other matter that may be an opportunity for us will not have any duty to communicate or offer such opportunity to us. Any such person or entity will not be liable to us or to any limited partner for breach of any 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. As a result, competition from GIP, its affiliates, and other companies in which it owns interests could materially and adversely impact our results of operations and distributable cash flow. 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.

GIP has pledged all of the equity interests that it owns in ENLC and ENLC's managing member to GIP's lenders under its credit facility. A default under GIP's credit facility could result in a change of control of our general partner.

GIP has pledged all of the equity interests that it owns in ENLC and ENLC's managing member to its lenders as security under a secured credit facility entered into by a GIP entity in connection with the GIP Transaction (the "GIP Credit Facility"). Although we are not a party to this credit facility, if GIP were to default under the GIP Credit Facility, GIP's lenders could foreclose on the pledged equity interests. Any such foreclosure on GIP's interest would result in a change of control of our general partner and 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 ENLC's Consolidated Credit Facility and Term Loan 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.

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, other than Enfield with respect to the Series B Preferred Units, any units held by a person that owns 20% or more of any class of units, 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 vote on any matter.

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

Our 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 our 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 our general partner to a third party or (ii) GIP 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 our 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 ofour general partner with its own choices and to control the decisions taken by the board of directors and officers.

Our partnership agreement replaces the fiduciary duties otherwise owed to our unitholders byour 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 thatour 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 asour 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 the general partner may make in its individual capacity include:

- how to allocate business opportunities among us and its other affiliates;
- 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 unitholders in connection with 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.

We may issue additional units, including units that are pari passu with our Series C Preferred Units, without the approval of the holders of the Series C Preferred Units.

We may issue an unlimited number of limited partner interests 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).

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 to decline and may adversely affect our ability to raise additional capital in the financial markets at times and prices favorable to us.

Our outstanding equity and debt securities are not listed on the NYSE or any other national securities exchange and, as a result, we are not obligated to comply with any exchange listing requirements.

Our outstanding equity and debt securities are not listed on the NYSE or any other national securities exchange, which means that we are exempt from any exchange listing requirements.

For so long as we do not have securities listed on a national securities exchange, we will not be required to have a majority of independent directors, an independent audit committee, or nominating, corporate governance, or compensation committees.

Accordingly, you may not have the same protections afforded to stockholders of companies that are subject to the corporate governance requirements of a national securities exchange.

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. 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.

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 Revised Uniform Limited Partnership Act ("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 from the date of distribution.

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.

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. Because a tax would be imposed upon us as a corporation, our cash available for distribution would be substantially reduced. Therefore, treatment of us as a corporation would result in a material reduction in our anticipated cash flow.

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 could be reduced.

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 our cash available for distribution 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, unless we are eligible to (and choose to) elect to push out those audit adjustments to those persons who were our unitholders during the tax period subject to such audit adjustments. If we make payments of taxes, penalties and interest resulting from audit adjustments, our cash available for distribution 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.

Treatment of distributions on our Series C Preferred Units as guaranteed payments for the use of capital is uncertain.

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.

Tax-exempt entities and non-U.S. persons face unique issues from owning our Series C Preferred Units which may result in adverse tax consequences to them.

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 an investment in our Series C Preferred 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 an investment in our Series C Preferred 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 Series C Preferred Units.

Entity level taxes on income from our C corporation subsidiary will reduce cash available for distribution.

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 our cash available for distribution.

Holders of Series C Preferred Units may be subject to state and local taxes and return filing or withholding requirements in jurisdictions where they do not live.

In addition to federal income taxes, holders of Series C Preferred Units may 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. Holders of Series C Preferred Units also may 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 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.

A unitholder whose Series C Preferred Units are loaned to a "short seller" to cover a short sale of units may be considered as having disposed of those units.

A holder of Series C Preferred Units 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 and, thus, may recognize gain or loss from such disposition. Our counsel has not rendered an opinion regarding the treatment of a unitholder where Series C Preferred Units are loaned to a short seller to cover a short sale of Series C Preferred Units; therefore, unitholders desiring to 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.

Item 4. Mine Safety Disclosures

Not applicable.

PART II

Item 5. Market for Registrant's Common Equity and Related Unitholder Matters.

Subsequent to the closing of the Merger, ENLC owns 100% of ENLK's common units.For equity compensation plan information, see the discussion under "Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Unitholder Matters—Equity Compensation Plan Information."

We will distribute all of our available cash, as defined in our partnership agreement, to ENLC, as the holder of all of our common units. Our available cash consists generally of all cash on hand at the end of any fiscal quarter or other applicable period plus all cash on hand on the date of determination resulting from working capital borrowings made after the end of such applicable period, less reserves that our general partner determines are necessary to:

- properly conduct our business;
- comply with applicable law, our debt instruments, or other agreements; and
- provide funds for distributions to the holders of the Series B Preferred Units and the Series C Preferred Units.

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.

Item 6. Selected Financial Data

The following tables present our selected historical financial and operating data ofENLK for the periods indicated. Financial and operating data for the years ended December 31, 2019, 2018, 2017, 2016, and 2015 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,				
	2019	2018	2017	2016	2015
	(In millions, except per unit data)				
Revenues:					
Product sales	$ 5,030.1	$ 6,512.3	$ 4,358.4	$ 3,008.9	$ 3,253.7
Product sales—related parties	—	41.0	144.9	134.3	119.4
Midstream services	1,008.4	763.3	552.3	467.2	451.0
Midstream services—related parties	—	377.2	688.2	653.1	618.6
Gain (loss) on derivative activity	14.4	5.2	(4.2)	(11.1)	9.4
Total revenues	6,052.9	7,699.0	5,739.6	4,252.4	4,452.1
Operating costs and expenses:					
Cost of sales (1)	4,392.5	6,008.0	4,361.5	3,015.5	3,245.3
Operating expenses	467.1	453.4	418.7	398.5	419.9
General and administrative	139.2	130.2	123.5	119.3	132.4
(Gain) loss on disposition of assets	(1.9)	0.4	—	13.2	1.2
Depreciation and amortization	617.0	577.3	545.3	503.9	387.3
Impairments	198.2	365.8	17.1	566.3	1,563.4
Loss on secured term loan receivable	52.9	—	—	—	—
Gain on litigation settlement	—	—	(26.0)	—	—
Total operating costs and expenses	5,865.0	7,535.1	5,440.1	4,616.7	5,749.5
Operating income (loss)	187.9	163.9	299.5	(364.3)	(1,297.4)
Other income (expense):					
Interest expense, net of interest income	(215.7)	(178.3)	(187.9)	(188.1)	(102.5)
Gain on extinguishment of debt	—	—	9.0	—	—
Income (loss) from unconsolidated affiliates	(16.8)	13.3	9.6	(19.9)	20.4
Other income	0.9	0.6	0.6	0.3	0.8
Total other expense	(231.6)	(164.4)	(168.7)	(207.7)	(81.3)
Income (loss) before non-controlling interest and income taxes	(43.7)	(0.5)	130.8	(572.0)	(1,378.7)
Income tax benefit (expense)	(2.5)	2.1	24.0	(1.3)	0.5
Net income (loss)	(46.2)	1.6	154.8	(573.3)	(1,378.2)
Net income (loss) attributable to non-controlling interests	8.1	2.1	1.1	(2.6)	(0.4)
Net income (loss) attributable to ENLK	$ (54.3)	$ (0.5)	$ 153.7	$ (570.7)	$ (1,377.8)
Distributions declared per limited partner unit	$ —	$ 1.560	$ 1.560	$ 1.560	$ 1.545

(1) Includes related party cost of sales of $21.7 million, $114.1 million, $211.0 million, $150.1 million, and $141.3 million for the years ended December 31, 2019, 2018, 2017, 2016, and 2015, respectively.

	EnLink Midstream Partners, LP				
	December 31,				
	2019	2018	2017	2016	2015
	(In millions)				
Balance Sheet Data (end of period):					
Property and equipment, net	$ 7,081.3	$ 6,846.7	$ 6,587.0	$ 6,256.7	$ 5,666.8
Total assets	9,134.6	9,571.3	9,414.0	9,153.4	8,092.8
Long-term debt (including current maturities)	4,764.3	4,319.6	3,467.8	3,268.0	3,066.8
Partners' equity including non-controlling interest	3,564.9	4,284.1	4,805.5	4,640.4	4,434.5

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 addition, please refer to the Definitions page set forth in this report prior to Item 1—Business. Discussions of the year ended December 31, 2017 and year-to-year comparisons of the year ended December 31, 2018 and the year ended December 31, 2017 can be found in "Management's Discussion and Analysis of Financial Condition and Results of Operations" in Part II, Item 7 of ENLK's Annual Report on Form 10-K for the year ended December 31, 2018.

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 the Operating Partnership.

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, and selling NGLs; and
- gathering, transporting, stabilizing, storing, trans-loading, and selling crude oil and condensate, in addition to brine disposal services.

Our midstream energy asset network includes approximately 12,000 miles of pipelines, 21 natural gas processing plants with approximately 5.3 Bcf/d of processing capacity, seven fractionators with approximately 290,000 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.

Effective January 1, 2019, we changed our reportable operating segments to reflect how we currently make financial decisions and allocate resources. Prior to January 1, 2019, our reportable operating segments consisted of the following: (i) natural gas gathering, processing, transmission, and fractionation operations located in North Texas and the Permian Basin, primarily in West Texas, (ii) natural gas pipelines, processing plants, storage facilities, NGL pipelines, and fractionation assets in Louisiana, (iii) natural gas gathering and processing operations located throughout Oklahoma, and (iv) crude rail, truck, pipeline, and barge facilities in West Texas, South Texas, Louisiana, Oklahoma, and ORV. Effective January 1, 2019, we report our financial performance in five segments:

- *Permian Segment.* The Permian segment includes our natural gas gathering, processing, and transmission activities and our crude oil operations in the Midland and Delaware Basins in West Texas and Eastern New Mexico and our crude operations in South Texas;

- *North Texas Segment.* The North Texas segment includes our natural gas gathering, processing, and transmission activities in North Texas;

- *Oklahoma Segment.* The Oklahoma segment includes our natural gas gathering, processing, and transmission activities, and our crude oil operations in the Cana-Woodford, Arkoma-Woodford, northern Oklahoma Woodford, STACK, and CNOW shale 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 and our crude oil operations in ORV; and

- *Corporate Segment.* The Corporate segment includes our unconsolidated affiliate investments in the Cedar Cove JV in Oklahoma, our ownership interest in GCF in South Texas, our derivative activity, and our general corporate assets and expenses.

We have recast the segment information for the years ended December 31, 2018 and December 31, 2017 to conform to the current period presentation.

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 most of our transactions is the use of our assets to transport a product or provide a processed product to an end-user or marketer at the tailgate of the plant, pipeline, or barge, truck, or rail terminal. 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 90% of our gross operating margin was derived from fee-based contractual arrangements with minimal direct commodity price exposure for the year ended December 31, 2019. We reflect revenue as "Product sales" and "Midstream services" on the consolidated statements of operations.

Devon is one of our primary customers. For the years ended December 31, 2019 and 2018, approximately 29.9% and 36.4% of our gross operating margin, respectively, was attributable to commercial contracts with Devon. For additional information about our significant customers, refer to "Item 1. Business—Credit Risks and Significant Customers."

Our revenues and gross operating margins are generated from volumes related to 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.

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 specified 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.

We typically buy mixed NGLs from our suppliers to 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 on our own gathering systems, third-party systems, and trucked from producers at a market index less a stated transportation deduction. We then transport and resell the crude oil and condensate through a process of basis and fixed price trades. 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, POL contracts, 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 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 our assets.

Recent Developments

Simplification of the Corporate Structure. On January 25, 2019, we completed the Merger, an internal reorganization pursuant to which ENLC owns all of the outstanding common units of ENLK. See "Item 8. Financial Statements and Supplementary Data—Note 1" for more information on the Merger and related transactions.

Transfer of EOGP Interest. On January 31, 2019, ENLC transferred its16.1% limited partner interest in EOGP to the Operating Partnership. See "Item 8. Financial Statements and Supplementary Data—Note 1" for more information regarding this transaction.

Organic Growth

Riptide Processing Plant. In September 2019, we completed construction of a 65 MMcf/d expansion to our Riptide processing plant in the Midland Basin, bringing the total operational processing capacity at the plant to 165 MMcf/d. We are currently in the process of further expanding our Riptide processing plant and expect an additional 55 MMcf/d of operational capacity to be completed during the fourth quarter of 2020.

Delaware Basin Processing Plant. In August 2019, we commenced construction of our Tiger Plant, which will expand our Delaware Basin processing capacity by an additional 200 MMcf/d. We expect the plant to be operational in the second half of 2020. This processing plant is owned by the Delaware Basin JV.

Central Oklahoma Plants. In June 2019, we commenced operations on our Thunderbird Plant, which expands our Central Oklahoma gas processing capacity by an additional 200 MMcf/d, bringing our total processing capacity at our Central Oklahoma facilities to 1.2 Bcf/d.

Cajun-Sibon Pipeline. In April 2019, we completed the expansion of our Cajun-Sibon NGL pipeline capacity, which connects the Mont Belvieu NGL hub to our fractionation facilities in Louisiana. This is the third phase of our Cajun-Sibon system referred to as Cajun Sibon III, which increases throughput capacity from 130,000 bbls/d to 185,000 bbls/d.

Lobo Natural Gas Gathering and Processing Facilities. In early April 2019, we completed construction of a 100 MMcf/d expansion to our Lobo III cryogenic gas processing plant, bringing the total operational processing capacity at our Lobo facilities to 375 MMcf/d.

Avenger Crude Oil Gathering System. Avenger is a crude oil gathering system in the northern Delaware Basin supported by a long-term contract with Devon on dedicated acreage in their Todd and Potato Basin development areas in Eddy and Lea counties in New Mexico. We commenced initial operations on Avenger during the third quarter of 2018 and began full-service operations during the second quarter of 2019.

Debt Issuances and Redemption

Issuance and Repayment of Senior Unsecured Notes. On April 9, 2019, ENLC issued $500.0 million in aggregate principal amount of ENLC's 5.375% senior unsecured notes due June 1, 2029 (the "2029 Notes") at a price to the public of 100% of their face value. Interest payments on the 2029 Notes are payable on June 1 and December 1 of each year. The 2029 Notes are fully and unconditionally guaranteed by ENLK. Net proceeds of approximately $496.5 million were used to repay outstanding borrowings under the Consolidated Credit Facility, including borrowings incurred on April 1, 2019 to repay at maturity all of the $400.0 million outstanding aggregate principal amount of ENLK's 2.70% senior unsecured notes due 2019, and for general limited liability company purposes. See "Item 8. Financial Statements and Supplementary Data—Note 6" for more information regarding this transaction.

Consolidated Credit Facility. On December 11, 2018, ENLC entered into the Consolidated Credit Facility, which we were able to borrow under upon the closing of the Merger. ENLK is a guarantor of the Consolidated Credit Facility. See "Item 8. Financial Statements and Supplementary Data—Note 6" for more information regarding this transaction.

Term Loan. On December 11, 2018, ENLK entered into a three-year$850.0 million unsecured term loan. Upon closing of the Merger, ENLC assumed ENLK's obligations under the term loan, and ENLK guaranteed ENLC's obligations thereunder. See "Item 8. Financial Statements and Supplementary Data—Note 6" for more information regarding this transaction.

Related Party Debt. Related party debt includes borrowings under the Consolidated Credit Facility, the Term Loan, and ENLC's 5.375% senior unsecured notes due 2029 to fund the operations and growth capital expenditures of ENLK through a related party arrangement with ENLC. See "Item 8. Financial Statements and Supplementary Data—Note 6" for more information regarding this arrangement.

GIP Transaction and Organic Growth in 2018

- On July 18, 2018, subsidiaries of Devon closed a transaction to sell all of their equity interests in ENLK, ENLC, and themanaging member of ENLC to GIP. See "Item 8. Financial Statements and Supplementary Data—Note 1" for more information regarding the GIP Transaction.

- During the second quarter of 2018, we completed construction of an expansion to our Lobo II cryogenic gas processing plant, which brought total operational processing capacity at our Lobo facilities to 175 MMcf/d. We further expanded our natural gas processing capacity at our Lobo facilities through the construction of the Lobo III cryogenic gas processing plant, which was completed during the fourth quarter of 2018 and provided an additional 100 MMcf/d of operational capacity.

- In late March 2018, we completed construction of Black Coyote.In addition, we further expanded our crude oil gathering operations in the STACK through the construction of Redbud, which is supported by a contract with Marathon Oil Company. We commenced initial operations on Redbud during the third quarter of 2018.

Non-GAAP Financial Measures

To assist management in assessing our business, we use the following non-GAAP financial measuregross operating margin.

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, condensate, and crude oil 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 to gross operating margin (in millions):

	Year Ended December 31,		
	2019	2018	2017
Operating income	$ 187.9	$ 163.9	$ 299.5
Add:			
Operating expenses	467.1	453.4	418.7
General and administrative	139.2	130.2	123.5
(Gain) loss on disposition of assets	(1.9)	0.4	—
Depreciation and amortization	617.0	577.3	545.3
Impairments	198.2	365.8	17.1
Loss on secured term loan receivable	52.9	—	—
Gain on litigation settlement	—	—	(26.0)
Gross operating margin	$ 1,660.4	$ 1,691.0	$ 1,378.1

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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,		
	2019	2018	2017
Permian Segment			
Revenues	$ 2,542.3	$ 3,030.3	$ 1,797.2
Cost of sales	(2,283.9)	(2,808.3)	(1,628.5)
Total gross operating margin	$ 258.4	$ 222.0	$ 168.7
North Texas Segment			
Revenues	$ 601.1	$ 684.1	$ 745.0
Cost of sales	(208.8)	(199.2)	(264.5)
Total gross operating margin	$ 392.3	$ 484.9	$ 480.5
Oklahoma Segment			
Revenues	$ 1,181.1	$ 1,299.8	$ 874.8
Cost of sales	(627.0)	(743.6)	(523.0)
Total gross operating margin	$ 554.1	$ 556.2	$ 351.8
Louisiana Segment			
Revenues	$ 2,622.8	$ 3,788.4	$ 3,182.2
Cost of sales	(2,181.6)	(3,365.7)	(2,800.9)
Total gross operating margin	$ 441.2	$ 422.7	$ 381.3
Corporate Segment			
Revenues	$ (894.4)	$ (1,103.6)	$ (859.6)
Cost of sales	908.8	1,108.8	855.4
Total gross operating margin	$ 14.4	$ 5.2	$ (4.2)
Total			
Revenues	$ 6,052.9	$ 7,699.0	$ 5,739.6
Cost of sales	(4,392.5)	(6,008.0)	(4,361.5)
Total gross operating margin	$ 1,660.4	$ 1,691.0	$ 1,378.1
Midstream Volumes:			
Permian Segment			
Gathering and Transportation (MMBtu/d)	723,400	521,900	361,200
Processing (MMBtu/d)	771,400	531,700	385,000
Crude Oil Handling (Bbls/d)	132,000	124,300	91,800
North Texas Segment			
Gathering and Transportation (MMBtu/d)	1,651,900	1,733,900	1,901,700
Processing (MMBtu/d)	750,500	747,400	799,400
Oklahoma Segment			
Gathering and Transportation (MMBtu/d)	1,302,200	1,204,700	829,300
Processing (MMBtu/d)	1,276,700	1,195,300	810,300
Crude Oil Handling (Bbls/d)	47,300	15,700	—
Louisiana Segment			
Gathering and Transportation (MMBtu/d)	2,050,000	2,196,200	1,995,800
Processing (MMBtu/d)	400,200	431,200	453,300
Crude Oil Handling (Bbls/d)	18,900	15,400	16,400
NGL Fractionation (Gals/d)	7,341,700	6,584,400	5,772,800
Brine Disposal (Bbls/d)	2,700	3,200	4,200

Year Ended December 31, 2019 Compared to Year Ended December 31, 2018

Gross Operating Margin. Gross operating margin was $1,660.4 million for the year ended December 31, 2019 compared to $1,691.0 million for the year ended December 31, 2018, a decrease of $30.6 million, or 1.8%, due to the following:

- *Permian Segment.* Gross operating margin in the Permian segment increased $36.4 million, which was primarily due to a $43.4 million increase in gross operating margin due to higher volumes on our Permian gas assets from continued development by our customers, including $26.7 million from our Delaware Basin assets, and $16.7 million from our Midland Basin assets. This increase was partially offset by a $7.0 million decrease in gross operating margin from our Permian crude assets, which was due to a $5.4 million decrease in gross operating margin from our South Texas assets due to an MVC expiration in July 2019 and a $4.5 million decrease in gross operating margin associated with our physical crude marketing arrangements partially offset by a $2.9 million increase in gross operating margin from our Midland and Delaware Basins crude assets. We manage our exposure to crude price fluctuations in our physical crude marketing arrangements through various derivative arrangements, which primarily relate to our Permian segment. The timing of our realization of the gains or losses from these crude derivative arrangements may not occur in the same period as the corresponding physical crude marketing transaction, and all associated gains and losses from the derivative arrangements are reflected in our Corporate segment.

- *North Texas Segment.* Gross operating margin in the North Texas segment decreased $92.6 million, which was primarily due to the January 1, 2019 expiration of Devon's obligations related to MVCs on our North Texas assets and normal volume declines due to limited new drilling in the region. Shortfall revenue from the Devon-related MVCs was $84.3 million for the year ended December 31, 2018.

- *Oklahoma Segment.* Gross operating margin in the Oklahoma segment decreased $2.1 million. Gross operating margin from our Oklahoma assets increased $43.4 million, which was primarily due to higher volumes from continued development by our customers, with $20.4 million contributed by our Oklahoma gas assets and $23.0 million contributed by our Oklahoma crude assets. These increases in gross operating margin for the year ended December 31, 2019 derived from our Oklahoma assets were offset by the recognition of $45.5 million in revenue from a contract restructuring with White Star during the year ended December 31, 2018.

- *Louisiana Segment.* Gross operating margin in the Louisiana segment increased $18.5 million. Gross operating margin from our NGL assets increased by $40.4 million primarily due to higher volumes with the completion of the Cajun-Sibon pipeline expansion in April 2019. Our ORV crude assets contributed an increase of $1.1 million primarily due to higher volumes. These increases were partially offset by a decrease of $23.0 million from our Louisiana gas business, primarily due to a $14.6 million decrease from a less favorable processing environment for our Louisiana gas plants and an $8.4 million decrease in our Louisiana gas transportation business due to the expiration of certain firm transportation contracts and decreased volumes during the same period.

- *Corporate Segment.* Gross operating margin in the Corporate segment increased $9.2 million, which was primarily due to the changes in fair value of our commodity swaps between the periods as summarized below (in millions):

	Year Ended December 31,	
	2019	2018
Realized swaps:		
Crude swaps	$ 11.7	$ (0.3)
NGL swaps	6.5	(3.2)
Gas swaps	(3.7)	(1.4)
Realized gain (loss) on derivatives	14.5	(4.9)
Unrealized swaps:		
Crude swaps	(0.3)	7.0
NGL swaps	(3.5)	8.3
Gas swaps	3.7	(5.2)
Change in fair value of derivatives	(0.1)	10.1
Gain on derivative activity	$ 14.4	$ 5.2

Certain gathering and processing agreements provide for quarterly or annual MVCs, including MVCs from Devon. Under these agreements, our customers agree to ship and/or process a minimum volume of commodity 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 commodity 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 product volumes and the MVCs were as follows (in millions):

	Permian	North Texas	Oklahoma	Total
Year Ended December 31, 2019				
Midstream services	$ 9.4	$ —	$ 10.3	$ 19.7
Total	$ 9.4	$ —	$ 10.3	$ 19.7
Year Ended December 31, 2018				
Midstream services (1)	$ 5.2	$ 41.0	$ 53.4	$ 99.6
Midstream services—related parties	6.3	43.3	1.2	50.8
Total	$ 11.5	$ 84.3	$ 54.6	$ 150.4

(1) We restructured a natural gas gathering and processing contract that contained MVCs. As a result, we recognized $45.5 million of midstream services revenue in the Oklahoma segment for the year ended December 31, 2018. For more information, see "Item 8. Financial Statements and Supplementary Data—Note 2."

On January 1, 2019, certain MVCs related to gathering and processing agreements with Devon for operations in the North Texas and Oklahoma segments expired. These MVCs generated $85.5 million in shortfall revenue for the year ended December 31, 2018. On July 31, 2019, an MVC related to a transportation services agreement with Devon for operations in the Permian segment expired. This MVC generated $9.4 million and $11.5 million in shortfall revenue for the years ended December 31, 2019 and 2018, respectively. For the year ended December 31, 2019, our MVC revenue in the Oklahoma segment was generated from a gathering and processing arrangement with Devon which expires in 2030, with the MVC provision under the agreement expiring in December 2020. This MVC generated $10.3 million in shortfall revenue for the year ended December 31, 2019. In 2020, this expiring MVC agreement is projected to generate approximately $55-$65 million in shortfall revenue.

Operating Expenses. Operating expenses were $467.1 million for the year ended December 31, 2019 compared to $453.4 million for the year ended December 31, 2018, an increase of $13.7 million, or 3.0%. The primary contributors to the total increase by segment were as follows (in millions):

	Year Ended December 31,		Change	
	2019	2018	$	%
Permian Segment	$ 112.9	$ 96.1	$ 16.8	17.5 %
North Texas Segment	102.9	112.7	(9.8)	(8.7)%
Oklahoma Segment	104.0	90.3	13.7	15.2 %
Louisiana Segment	147.3	154.3	(7.0)	(4.5)%
Total	$ 467.1	$ 453.4	$ 13.7	3.0 %

- *Permian Segment.* Operating expenses in the Permian segment increased $16.8 million primarily due to expanded operations and higher utilities expense, bulk purchases of materials and supplies, construction fees and services, and compressor rentals.

- *North Texas Segment.* Operating expenses in the North Texas segment decreased $9.8 million primarily due to decreased compressor rentals, compressor overhauls, and labor and benefits costs.

- *Oklahoma Segment.* Operating expenses in the Oklahoma segment increased $13.7 million primarily due to expanded operations with increases in utilities, equipment rentals, compression operations and maintenance, and labor and benefits costs.

- *Louisiana Segment.* Operating expenses in the Louisiana segment decreased $7.0 million primarily due to reduced materials and supplies expenses, labor and benefits costs, and compression rentals partially offset by increased equipment rental and utility costs.

General and Administrative Expenses. General and administrative expenses were $139.2 million for the year ended December 31, 2019 compared to $130.2 million for the year ended December 31, 2018, an increase of $9.0 million, or 6.9%. The primary contributors to the increase were as follows:

- Fees and services expense increased $4.6 million, which was primarily due to increased software consulting and legal fees.

- Other office expense increased $2.9 million, which was primarily due to a reduction of expense allocation to ENLC as a result of the Merger, which closed during the first quarter of 2019.

- Unit-based compensation expense increased $2.5 million, which was primarily due to increased bonus expense and accelerated vesting of units related to an executive departure in the third quarter of 2019. This increase was partially offset by accelerated vesting of units related to the GIP Transaction during 2018.

- Labor and benefits costs decreased $0.7 million. Labor and benefit costs for the year ended December 31, 2019 included severance costs of $7.0 million, driven by an executive departure and a reduction in workforce, compared to $3.0 million in severance costs for the year ended December 31, 2018. The $4.0 million increase in severance costs between years was offset by a decrease in bonus expense of $5.5 million.

- Transaction costs decreased $1.0 million, which was primarily due to costs incurred related to the Merger, which closed during the first quarter of 2019, compared to the costs of transactions related to the GIP Transaction, which closed during 2018.

Depreciation and Amortization. Depreciation and amortization expenses were $617.0 million for the year ended December 31, 2019 compared to $577.3 million for the year ended December 31, 2018, an increase of $39.7 million, or 6.9%. This increase was primarily due to increased depreciation of $32.5 million attributable to new assets placed into service in key growth areas, including the Thunderbird Plant, the expansion of the Lobo III cryogenic gas processing plant, the Cajun-Sibon NGL pipeline, Avenger, the Black Coyote crude oil gathering system, and well connections in Oklahoma. Additionally, depreciation increased by $18.3 million primarily due to retirements and reductions in our estimated useful lives of certain assets primarily located in the Texas and Louisiana segments. These increases were partially offset by a $11.1 million decrease in depreciation during 2019 resulting from an impairment of the carrying value of certain non-core crude pipeline assets during 2018.

Impairments. Impairment expense was $198.2 million for the year ended December 31, 2019, which was primarily related to $190.3 million of recognized goodwill impairment for our Oklahoma reporting unit. We also recorded a $7.9 million impairment on property and equipment related to certain decommissioned and removed non-core assets. For the year ended December 31, 2018, we recognized impairments on property and equipment related to the carrying values of certain non-core natural gas assets in the Louisiana segment of $24.6 million and $109.2 million related to non-core crude pipeline assets in the Permian segment. In addition, we recognized goodwill impairments for our North Texas and Permian reporting units of $202.7 million and $29.3 million, respectively. See "Item 8. Financial Statements and Supplementary Data—Note 3" for additional information about our goodwill impairments.

Loss on secured term loan receivable. We have recorded a $52.9 million loss in our consolidated statement of operations for the year ended December 31, 2019 related to the write-off of the White Star secured term loan receivable. For additional information regarding this transaction, refer to "Item 8. Financial Statements and Supplementary Data—Note 2."

Interest Expense. Interest expense was $215.7 million for the year ended December 31, 2019 compared to $178.3 million for the year ended December 31, 2018, an increase of $37.4 million, or 21.0%. Net interest expense consisted of the following (in millions):

	Year Ended December 31,	
	2019	2018
Senior notes	$ 151.8	$ 160.0
Related Party Debt	66.0	—
Term Loan	—	1.9
ENLK Credit Facility	0.3	22.3
Capitalized interest	(5.8)	(7.0)
Amortization of debt issuance costs and net discount	4.9	4.0
Other	(1.5)	(2.9)
Total interest expense, net of interest income	$ 215.7	$ 178.3

Income (loss) from Unconsolidated Affiliate Investments. Loss from unconsolidated affiliate investments was $16.8 million for the year ended December 31, 2019 compared to income of $13.3 million for the year ended December 31, 2018, a decrease in income of $30.1 million. The reduction in income was primarily due to a $31.4 million impairment of the carrying value of the Cedar Cove JV, as we determined that the carrying value of our investment was not recoverable based on the forecasted cash flows from the Cedar Cove JV.

Year Ended December 31, 2018 Compared to Year Ended December 31, 2017

We have recast the segment information for the years ended December 31, 2018 and December 31, 2017 to conform to the current period presentation.

Gross Operating Margin. Gross operating margin was $1,691.0 million for the year ended December 31, 2018 compared to $1,378.1 million for the year ended December 31, 2017, an increase of $312.9 million, or 22.7%, due to the following:

- *Permian Segment.* Gross operating margin in the Permian segment increased $53.3 million, which was primarily due to a $42.7 million increase from our Permian Basin processing assets as a result of higher volumes due to continued development by our customers. In addition, there was a $5.9 million increase from our Permian Basin crude business as a result of increased trucking volumes, higher trucking fees, higher volumes due to continued expansion of our customer base on the Greater Chickadee gathering system, and the start of initial operations of Avenger and $2.3 million due to higher volumes on VEX.

- *North Texas Segment.* Gross operating margin in the North Texas segment increased $4.4 million, which was primarily due to an increase in processing, gathering, and transmission volumes associated with new development in the Barnett

Shale. For the year ended December 31, 2018, the shortfall revenue from Devon-related MVCs was $84.3 million compared to $59.2 million for the year ended December 31, 2017.

- *Oklahoma Segment.* Gross operating margin in the Oklahoma segment increased $204.4 million, which was primarily due to a $156.3 million increase from higher volumes as a result of continued development by our customers. In addition, during the year ended December 31, 2018, we restructured a contract with a customer, which resulted in the recognition of $45.5 million in revenue for the year ended December 31, 2018 (as discussed in "Item 8. Financial Statements and Supplementary Data—Note 2"). Additionally, gross operating margin increased $2.5 million from the start of initial operations of our Central Oklahoma crude oil gathering systems and trucking business. For the year ended December 31, 2018, the shortfall revenue from Devon-related MVCs was $1.2 million compared to $13.8 million for the year ended December 31, 2017.

- *Louisiana Segment.* Gross operating margin in the Louisiana segment increased $41.4 million, which was primarily due to a $29.0 million increase in our NGL transmission and fractionation gross operating margin due to additional NGL volumes received from our Oklahoma and Permian Basin assets and fees earned from the start-up of our Ascension JV assets in April 2017. In addition, there was a $14.9 million increase from ORV due to higher condensate stabilization volumes and improved margins from contract renegotiations.

- *Corporate Segment.* Gross operating margin in the Corporate segment increased $9.4 million, due to the changes in fair value of our commodity swaps between the periods. For the year ended December 31, 2018, there were realized losses of $4.9 million that were offset by unrealized gains of $10.1 million. For the year ended December 31, 2017, there were realized losses of $8.9 million that were partially offset by unrealized gains of $4.7 million.

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

	Permian	North Texas	Oklahoma	Total
Year Ended December 31, 2018				
Midstream services (1)	$ 5.2	$ 41.0	$ 53.4	$ 99.6
Midstream services—related parties	6.3	43.3	1.2	50.8
Total	$ 11.5	$ 84.3	$ 54.6	$ 150.4
Year Ended December 31, 2017				
Midstream services	$ —	$ 0.8	$ 16.1	$ 16.9
Midstream services—related parties	8.9	59.2	13.8	81.9
Total	$ 8.9	$ 60.0	$ 29.9	$ 98.8

(1) We restructured a natural gas gathering and processing contract that contained MVCs. As a result, we recognized $45.5 million of midstream services revenue in the Oklahoma segment for the year ended December 31, 2018. For more information, see "Item 8. Financial Statements and Supplementary Data—Note 2."

Operating Expenses. Operating expenses were $453.4 million for the year ended December 31, 2018 compared to $418.7 million for the year ended December 31, 2017, an increase of $34.7 million, or 8.3%. The primary contributors to the total increase by segment were as follows (in millions):

	Year Ended December 31,		Change	
	2018	2017	$	%
Permian Segment	$ 96.1	$ 85.1	$ 11.0	12.9 %
North Texas Segment	112.7	121.8	(9.1)	(7.5)%
Oklahoma Segment	90.3	64.6	25.7	39.8 %
Louisiana Segment	154.3	147.2	7.1	4.8 %
Total	$ 453.4	$ 418.7	$ 34.7	8.3 %

- *Permian Segment.* Operating expenses in the Permian segment increased $11.0 million primarily due to expanded operations and higher utilities expense.

- *North Texas Segment.* Operating expenses in the North Texas segment decreased $9.1 million primarily due to decreases in materials and supplies, equipment rentals, and operational fees and services.

- *Oklahoma Segment.* Operating expenses in the Oklahoma segment increased $25.7 million primarily due to labor and benefit expenses from increased headcount, as well as an increase in materials and supplies, operational fees and services, treater rentals, ad valorem tax, and compression service expenses as a result of expanded operations.

- *Louisiana Segment.* Operating expenses in the Louisiana segment increased $7.1 million primarily due to increased utilities, operational fees and services, labor and benefits charges, and materials and supplies expenses as a result of the start-up of the Ascension JV in April 2017 and higher volumes across our Louisiana assets.

Impairments. Impairment expense was $365.8 million for the year ended December 31, 2018, compared to impairment expense of $17.1 million for the year ended December 31, 2017, an increase of $348.7 million. For the year ended December 31, 2018, we recognized impairments on property and equipment related to the carrying values of certain non-core natural gas assets in the Louisiana segment of $24.6 million and $109.2 million related to non-core crude pipeline assets in the Permian segment. In addition, we recognized goodwill impairments for our North Texas and Permian reporting units of $202.7 million and $29.3 million, respectively. For the year ended December 31, 2017, we recognized a $17.1 million impairment on property and equipment, which related to the carrying values of rights-of-way that we are no longer using and an abandoned brine disposal well. See “Item 8. Financial Statements and Supplementary Data—Note 3” for additional information.

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 interpretation and implementation 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 and future accounting standards to be adopted.

Impairment of Long-Lived Assets

In accordance with ASC 360, *Property, Plant, and Equipment*, we evaluate long-lived assets, including related intangible assets, of identifiable business activities for potential impairment annually in the fourth quarter, and 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 is recognized equal to the excess of the asset’s carrying value over its fair value, which is based on inputs that are not observable in the market, and thus represent Level 3 inputs. For additional information about our long-lived asset impairment tests, refer to “Item 8. Financial Statements and Supplementary Data—Note 2.”

For the year ended December 31, 2019, we recognized a $7.9 million impairment on property and equipment related to certain decommissioned and removed non-core assets.

For the year ended December 31, 2018, we determined that the undiscounted cash flows for two of our assets were not in excess of their carrying values. We estimated the fair values of these assets and determined that their fair values were not in excess of their carrying values, which resulted in impairments on property and equipment of $24.6 million related to certain non-core natural gas pipeline assets in the Louisiana segment and $109.2 million related to non-core crude pipeline assets in the Permian segment.

Impairment of 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. 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.

For additional information about our goodwill impairment tests, refer to "Item 8. Financial Statements and Supplementary Data—Note 3."

Goodwill Impairment Analysis for the Year Ended December 31, 2019

During the fourth quarter of 2019, we performed a quantitative analysis as of October 31, 2019 for our annual goodwill impairment test. Subsequent to October 31, 2019, we determined that due to a significant decline in ENLC's common unit price and the expected reduction in ENLC's cash distribution paid to common unitholders, which was announced in January 2020, a change in circumstances had occurred that warranted an additional quantitative impairment test. We recorded a goodwill impairment loss of $190.3 million on our Oklahoma reporting unit. This amount is included in impairments in the consolidated statement of operations for the year ended December 31, 2019.

Goodwill Impairment Analysis for the Year Ended December 31, 2018

During our annual goodwill impairment test for 2018, which was performed as of October 31, 2018, we determined, based upon our qualitative assessment, that no impairments of goodwill were required as of that date. However, subsequent to October 31, 2018, we determined that due to a significant decline in our unit price, a change in circumstances had occurred that warranted a quantitative impairment test. Based on this triggering event, we performed a quantitative goodwill impairment analysis as of December 31, 2018. Based on this analysis, a goodwill impairment loss for our Permian and North Texas reporting units in the amounts of $29.3 million and $202.7 million, respectively, was recognized in the fourth quarter of 2018 and is included in impairments in the consolidated statement of operations for the year ended December 31, 2018.

We concluded that the fair value of our Oklahoma and Corporate reporting units exceeded their carrying values, and the amounts of goodwill disclosed on the consolidated balance sheet associated with these reporting units were recoverable. Therefore, no goodwill impairment was identified or recorded for these reporting units as a result of our quantitative impairment test.

Liquidity and Capital Resources

Cash Flows from Operating Activities. Net cash provided by operating activities was $984.5 million and $856.8 million for the years ended December 31, 2019 and 2018, respectively. Operating cash flows and changes in working capital for comparative periods were as follows (in millions):

	Year Ended December 31,	
	2019	2018
Operating cash flows before working capital	$ 899.8	$ 928.2
Changes in working capital	84.7	(71.4)

Operating cash flows before changes in working capital decreased $28.4 million for the year ended December 31, 2019 compared to the year ended December 31, 2018. The primary contributors to the decrease in operating cash flows were as follows:

- General and administrative expenses excluding unit-based compensation increased $6.5 million, primarily due to higher transaction costs related to the Merger in January 2019. For more information, see "Results of Operations."
- Operating expenses excluding unit-based compensation increased $17.7 million primarily due to expanded operations. For more information, see "Results of Operations."

- Interest expense, excluding amortization of debt issue costs and net discounts,increased $36.5 million.

These changes to operating cash flows were partially offset by a$25.1 million increase in gross operating margin, excluding unrealized gains and losses on derivative activity and excluding non-cash revenue recognized from the restructuring of a contract (as discussed in "Item 8. Financial Statements and Supplementary Data—Note 2").

The changes in working capital for the years ended December 31, 2019 and 2018 were primarily due to fluctuations in trade receivable and payable balances due to timing of collection and payments, changes in inventory balances attributable to normal operating fluctuations, and fluctuations in accrued revenue and accrued cost of sales.

Cash Flows from Investing Activities. Net cash used in investing activities was $741.5 million and $826.3 million for the years ended December 31, 2019 and 2018, respectively. Our primary investing cash flows were as follows (in millions):

	Year Ended December 31,	
	2019	2018
Growth capital expenditures	$ (709.0)	$ (800.3)
Maintenance capital expenditures	(45.9)	(42.8)
Proceeds from sale of property	14.3	1.9

Growth capital expenditures decreased $91.3 million for the year ended December 31, 2019 compared to the year ended December 31, 2018. The decrease was primarily due to lower overall growth capital expenditures due to the completion of Avenger and the Lobo III gas processing plant in the Delaware Basin in 2018, compared to the capital expenditures in 2019 related to the Lobo III cryogenic gas processing plant expansion, the Thunderbird Plant, the expansion of the Cajun-Sibon NGL pipeline, and the expansion of the Riptide processing plant.

Maintenance capital expenditures increased by $3.1 million for the year ended December 31, 2019 compared to the year ended December 31, 2018. This increase was primarily due to larger asset bases year-over-year and the timing of expenditures.

Proceeds from the sale of assets increased $12.4 million for the year ended December 31, 2019 compared to the year ended December 31, 2018, primarily due to the sale of certain non-core assets during 2019.

Cash Flows from Financing Activities. Net cash used in financing activities was $265.1 million for the year ended December 31, 2019. Net cash provided by financing activities was $38.2 million for the year ended December 31, 2018. Our primary financing activities consisted of the following (in millions):

	Year Ended December 31,	
	2019	2018
Net borrowings on related party debt	$ 850.0	$ —
Unsecured senior notes repayments	(400.0)	—
Proceeds from the Term Loan	—	850.0
Proceeds from issuance of common units	—	46.1
Payment of installment payable for EOGP acquisition	—	(250.0)
Contributions by non-controlling partners (1)	97.5	156.4
Distributions to non-controlling interests (2)	(24.1)	(54.5)
Distributions to common units (3)	(667.0)	(551.6)
Distribution to general partner interest (including incentive distribution rights) (4)	(15.6)	(61.9)
Distributions to Series B Preferred unitholders (5)	(67.4)	(65.0)
Distributions to Series C Preferred unitholders (5)	(24.0)	(24.0)

(1) Represents contributions from NGP to the Delaware Basin JV of $97.5 million and $90.5 million for the years ended December 31, 2019 and 2018, respectively. Represents contributions from ENLC to EOGP of $66.2 million for the year ended December 31, 2018.
(2) Represents distributions to NGP for its ownership in the Delaware Basin JV and distributions to Marathon Petroleum Corporation for its ownership in the Ascension JV for the years December 31, 2019 and 2018. Includes distributions to ENLC for its ownership in EOGP for the year ended December 31, 2018.
(3) Subsequent to the closing of the Merger, we no longer have publicly held common units. ENLC owns all of our outstanding common units and we make quarterly distributions to ENLC related to its ownership of our common units.
(4) At the closing of the Merger, our general partner's incentive distribution rights were eliminated.
(5) See "Item 8. Financial Statements and Supplementary Data—Note 8" for information on distributions to holders of the Series B Preferred Units and Series C Preferred Units.

Related party debt includes borrowings under the Consolidated Credit Facility, the Term Loan, and ENLC's 5.375% senior unsecured notes due 2029 to fund the operations and growth capital expenditures of ENLK through a related party arrangement with ENLC. See "Item 8. Financial Statements and Supplementary Data—Note 6" for additional information.

On April 9, 2019, ENLC issued $500.0 million in aggregate principal amount of ENLC's 5.375% senior unsecured notes due June 1, 2029 at a price to the public of 100% of their face value. Interest payments on the 2029 Notes are payable on June 1 and December 1 of each year. The 2029 Notes are fully and unconditionally guaranteed by ENLK. Net proceeds of approximately $496.5 million were used to repay outstanding borrowings under the Consolidated Credit Facility, including borrowings incurred on April 1, 2019 to repay at maturity all of the $400.0 million outstanding aggregate principal amount of ENLK's 2.70% senior unsecured notes due 2019, and for general limited liability company purposes.

On December 11, 2018, we entered into a Term Loan due December 11, 2021, and used the net proceeds to repay borrowings under the ENLK Credit Facility. At the closing of the Merger, ENLC assumed the Term Loan, and we became a guarantor of ENLC's obligations under the Term Loan. Also, at the closing of the Merger, the ENLK Credit Facility was terminated and we became a guarantor of the Consolidated Credit Facility. See "Item 8. Financial Statements and Supplementary Data—Note 6" for additional information.

For the year ended December 31, 2018, we sold an aggregate of 2.6 million common units under the 2017 EDA, generating proceeds of $46.1 million (net of $0.5 million of commissions paid to the ENLK Sales Agents). We used the net proceeds for general partnership purposes. In connection with the announcement of the Merger, we suspended solicitation and offers under the 2017 EDA. Following the consummation of the Merger, the 2017 EDA was terminated.

For the year ended December 31, 2018, we made the final $250.0 million payment under the installment payable obligation related to the EOGP acquisition.

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 2020 growth capital expenditures, including capital contributions to our unconsolidated affiliate investments, to be approximately$275 million to $375 million, which is net of approximately $60 million to $80 million from our joint venture partners. We expect our2020 maintenance capital expenditures to be $40 million to $50 million. Our primary capital projects for 2020 include the construction of the Tiger Plant in the Delaware Basin and continued development of our existing systems. See "Recent Developments" for further details.

We expect to fund growth capital expenditures from operating cash flows and 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 2020, it is possible that not all of our 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, 2019 and 2018.

Total Contractual Cash Obligations. A summary of our total contractual cash obligations as of December 31, 2019 is as follows (in millions):

	Payments Due by Period						
	Total	2020	2021	2022	2023	2024	Thereafter
Long-term debt obligations	$ 3,100.0	$ —	$ —	$ —	$ —	$ 550.0	$ 2,550.0
Related party debt	1,700.0	—	850.0	—	—	350.0	500.0
Interest payable on fixed long-term debt obligations	2,514.1	176.0	176.0	176.0	176.0	163.9	1,646.2
Operating lease obligations	141.2	25.0	18.7	11.7	9.7	9.1	67.0
Purchase obligations	21.2	21.2	—	—	—	—	—
Pipeline and trucking capacity and deficiency agreements (1)	191.9	39.4	37.7	31.8	28.1	19.0	35.9
Inactive easement commitment (2)	10.0	—	—	10.0	—	—	—
Total contractual obligations	$ 7,678.4	$ 261.6	$ 1,082.4	$ 229.5	$ 213.8	$ 1,092.0	$ 4,799.1

(1) Consists of pipeline capacity payments for firm transportation and deficiency agreements.
(2) 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 and NGLs 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 that is not already disclosed in the table above.

The interest payable under the related party debt related to the Consolidated Credit Facility and the Term Loan are not reflected in the above table because such amounts depend on the outstanding balances and interest rates of the Consolidated Credit Facility and the Term Loan, which vary from time to time.

Our contractual cash obligations for 2020 are expected to be funded from cash flows generated from our operations.

Indebtedness

We have a related party debt arrangement with ENLC to fund the operations and growth capital expenditures of ENLK. Interest charged to ENLK for borrowings made through the related party arrangement is substantially the same as interest charged to ENLC on borrowings from third party lenders. The indebtedness under ENLC's 5.375% senior unsecured notes due June 1, 2029, the Consolidated Credit Facility, and the Term Loan was incurred by ENLC but is guaranteed by ENLK. Therefore, the covenants in the agreements governing such indebtedness described in "Item 8. Financial Statements and Supplementary Data—Note 6" affect balances owed by ENLK on the related party debt. As of December 31, 2019, we have $500.0 million in aggregate principal amount of indebtedness through the related party debt arrangement with ENLC relating to ENLC's 5.375% unsecured senior notes due 2029.

In addition, as of December 31, 2019, we have $3.1 billion in aggregate principal amount of outstanding unsecured senior notes maturing from 2024 to 2047.

See "Item 8. Financial Statements and Supplementary Data—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 2018 and 2019. 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 13."

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 within the meaning of the federal securities laws. Although these statements reflect the current views, assumptions and expectations of our management, the matters addressed herein involve certain assumptions, risks and uncertainties that could cause actual activities, performance, outcomes and results to differ materially from those indicated herein. Therefore, you should not rely on any of these forward-looking statements. 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," "expect," "continue," and similar expressions. Such forward-looking statements include, but are not limited to, statements about when additional capacity will be operational, timing for completion of construction or expansion projects, results in certain basins, profitability, financial metrics, operating efficiencies and other benefits of cost savings or operational initiatives, our future capital structure and credit ratings, objectives, strategies, expectations, and intentions, and other statements that are not historical facts. Factors that could result in such differences or otherwise materially affect our financial condition, results of operation, or cash flows, include, without limitation, (a) potential conflicts of interest of GIP with us and the potential for GIP to favor GIP's own interests to the detriment of our unitholders, (b) GIP's ability to compete with us and the fact that it is not required to offer us the opportunity to acquire additional assets or businesses, (c) a default under GIP's credit facility could result in a change in control of us and a default under ENLC's Consolidated Credit Facility and Term Loan, (d) the dependence on Devon for a substantial portion of the natural gas and crude that we gather, process, and transport, (e) developments that materially and adversely affect Devon or other customers, (f) adverse developments in the midstream business that may reduce our ability to make distributions, (g) competition for crude oil, condensate, natural gas, and NGL supplies and any decrease in the availability of such commodities, (h) decreases in the volumes that we gather, process, fractionate, or transport, (i) construction risks in our major development projects, (j) our ability to receive or renew required permits and other approvals, (k) increased federal, state, and local legislation, and regulatory initiatives, as well as government reviews relating to hydraulic fracturing resulting in increased costs and reductions or delays in natural gas production by our customers, (l) climate change legislation and regulatory initiatives resulting in increased operating costs and reduced demand for the natural gas and NGL services we provide, (m) changes in the availability and cost of capital, including as a result of a change in our credit rating, (n) volatile prices and market demand for crude oil, condensate, natural gas, and NGLs that are beyond our control, (o) 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, (p) operating hazards, natural disasters, weather-related issues or delays, casualty losses, and other matters beyond our control, (q) reductions in demand for NGL products by the petrochemical, refining, or other industries or by the fuel markets, (r) impairments to goodwill, long-lived assets and equity method investments, and (s) the effects of existing and future laws and governmental regulations, including environmental and climate change requirements and other uncertainties. In addition to the specific uncertainties, factors and risks discussed above and 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 CFTC to regulate certain markets for derivative products, including OTC derivatives. The CFTC has issued several relevant regulations, and other rulemakings are pending at the CFTC, the product of which would be rules that implement the mandates in the 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 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. The CFTC proposed new rules in January 2020 (withdrawing previously proposed rules from November 2013 and December 2016) 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 sought comment on the position limits rules as reproposed and revised, but the new rules have not yet been issued in final form, and the impact of any final provisions on us is uncertain at this time.

The legislation and potential 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 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.

Commodity Price Risk

Commodity prices were volatile during 2019. Crude oil prices increased 31% while weighted average NGL prices and natural gas prices decreased 25% and 26%, respectively, from January 1, 2019 to December 31, 2019. 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 2019 ranged from a high of $66.30 per Bbl in April 2019 to a low of $46.54 per Bbl in January 2019. Weighted average NGL prices in 2019 (based on the Oil Price Information Service ("OPIS") Napoleonville daily average spot liquids prices) ranged from a high of $0.56 per gallon in February 2019 to a low of $0.25 per gallon in July 2019. Natural gas prices (based on Gas Daily Henry Hub closing prices) during 2019 ranged from a high of $3.59 per MMBtu in January 2019 to a low of $2.07 per MMBtu in August 2019.

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 90% of our gross operating margin for the year ended December 31, 2019 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, 2019, less than 1% of our gross operating margin was generated from processing margin contracts.

3. *POL 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 POL contracts, but they do decline during periods of low liquids prices.

4. *POP contracts:* Under these contracts, we receive a fee in the form of 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 POP contracts, but they do decline during periods of low natural gas and liquids prices.

For the year ended December 31, 2019, approximately 7% of our gross operating margin was generated from POL or POP 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, crude and condensate, and NGLs using OTC derivative financial instruments with only certain well-capitalized counterparties which have been approved in accordance with our commodity risk management policy.

We have hedged our exposure to fluctuations in prices for natural gas, NGLs, and crude oil volumes produced for our account. We have tailored our hedges to generally match the product composition and the delivery points to those of our physical equity volumes. The hedges cover specific products based upon our expected equity composition.

The following table sets forth certain information related to derivative instruments outstanding at December 31, 2019 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 Oil Price Information Service. 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)	Net Fair Value Asset/(Liability) (In millions)
January 2020 - September 2020	Ethane	380 (MBbls)	$0.1692/gal	Index	$ (0.5)
January 2020 - September 2020	Propane	954 (MBbls)	Index	$0.4399/gal	1.9
January 2020 - September 2020	Normal butane	339 (MBbls)	Index	$0.6136/gal	(0.3)
January 2020 - September 2020	Natural gasoline	130 (MBbls)	Index	$1.2148/gal	0.1
January 2020 - January 2021	Natural gas	23,123 (MMBtu/d)	Index	$2.0241/MMBtu	0.6
January 2020 - July 2020	Crude and condensate	130 (MBbls)	Index	$55.60/Bbl	0.4
January 2020 - December 2022	Crude and condensate	10,933 (MBbls)	$2.015/Bbl	Index (2)	6.2
					$ 8.4

(1) Weighted average.
(2) Represents the WTI Houston and WTI Midland differential.

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, 2019, outstanding natural gas swap agreements, NGL swap agreements, swing swap agreements, storage swap agreements, and other derivative instruments had a net fair value asset of $8.4 million. The aggregate effect of a hypothetical 10% change, increase or decrease, in gas, crude and condensate, and NGL prices would result in a change of approximately $4.1 million in the net fair value of these contracts as of December 31, 2019.

Interest Rate Risk

We are exposed to interest rate risk on the Consolidated Credit Facility and the Term Loan through the related party debt arrangement with ENLC. At December 31, 2019, we had $1,700.0 million in outstanding borrowings under the related party debt arrangement, of which $1,200.0 million was related to the Consolidated Credit Facility and the Term Loan. In April 2019, we entered into $850.0 million of interest rate swaps to reduce the variability of cash outflows associated with interest payments related to our long-term debt with variable interest rates. These swaps have been designated as cash flow hedges. See “Item 8. Financial Statements and Supplementary Data—Note 11” for more information on our outstanding derivatives. A 1.0% increase or decrease in interest rates would change our annualized interest expense by approximately $12.0 million related to the Consolidated Credit Facility and the Term Loan. This change in interest expense would be partially offset by an $8.5 million change related to our open interest rate swap hedge.

We are not exposed to changes in interest rates with respect to our senior unsecured notes due in 2024, 2025, 2026, 2044, 2045, or 2047 or ENLC's senior unsecured notes due in 2029 as these are fixed-rate obligations. As of December 31, 2019, the estimated fair value of our senior unsecured notes and ENLC's senior unsecured notes was approximately $2,771.2 million and $473.0 million, respectively, based on the market prices of our and ENLC's publicly traded debt at December 31, 2019. Market risk is estimated as the potential decrease in fair value of our long-term debt resulting from a hypothetical increase of 1.0% in interest rates. Such an increase in interest rates would result in an approximate $231.0 million decrease in fair value of the senior unsecured notes at December 31, 2019. See "Item 8. Financial Statements and Supplementary Data—Note 6" for more information on our outstanding indebtedness.

Item 8. Financial Statements and Supplementary Data

INDEX TO FINANCIAL STATEMENTS

EnLink Midstream Partners, LP and Subsidiaries Financial Statements:

**MANAGEMENT'S REPORT ON
INTERNAL CONTROL OVER FINANCIAL REPORTING**

Management of EnLink Midstream GP, LLC, our general partner, 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 Midstream 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 EnLink Midstream 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, 2019, 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, 2019, 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.

Report of Independent Registered Public Accounting Firm

To the Partners of EnLink Midstream Partners, LP and
Board of Directors of EnLink Midstream GP, LLC:

Opinion on the Consolidated Financial Statements

We have audited the accompanying consolidated balance sheets of EnLink Midstream Partners, LP and subsidiaries (the Partnership) as ofDecember 31, 2019 and 2018, 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, 2019, and the related notes (collectively, the consolidated financial statements). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Partnership as of December 31, 2019 and 2018, and the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2019, in conformity with U.S. generally accepted accounting principles.

Change in Accounting Principles

As discussed in Note 2(x) to the consolidated financial statements, the Partnership has changed its method of accounting for leases in 2019 due to the adoption of Accounting Standards Codification 842, *Leases*. As discussed in Note 2(c) to the consolidated financial statements, the Partnership has changed its method of accounting for revenue recognition in 2018 due to the adoption of Accounting Standards Codification 606, *Revenue from Contracts with Customers.*

Basis for Opinion

These consolidated financial statements are the responsibility of the management of EnLink Midstream GP, LLC, the general partner of EnLink Midstream Partners, LP. Our responsibility is to express an opinion on these consolidated financial statements 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 the Partnership in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud. The Partnership is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits, we are required to obtain an understanding of internal control over financial reporting but not for the purpose of expressing an opinion on the effectiveness of the Partnership's internal control over financial reporting. Accordingly, we express no such opinion.

Our audits 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. We believe that our audits provide a reasonable basis for our opinion.

/s/ KPMG LLP

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

Dallas, Texas
February 26, 2020

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

	December 31, 2019	December 31, 2018
ASSETS		
Current assets:		
Cash and cash equivalents	$ 77.4	$ 99.5
Accounts receivable:		
Trade, net of allowance for bad debt of $0.5 and $0.3, respectively	36.2	126.3
Accrued revenue and other	460.1	705.9
Related party	18.1	2.1
Fair value of derivative assets	12.9	28.6
Natural gas and NGLs inventory, prepaid expenses, and other	56.9	72.8
Total current assets	661.6	1,035.2
Property and equipment, net of accumulated depreciation of $3,418.6 and $2,967.4, respectively	7,081.3	6,846.7
Intangible assets, net of accumulated amortization of $545.9 and $422.2, respectively	1,249.9	1,373.6
Goodwill	—	190.3
Investment in unconsolidated affiliates	43.1	80.1
Fair value of derivative assets	4.3	4.1
Other assets, net	94.4	41.3
Total assets	$ 9,134.6	$ 9,571.3
LIABILITIES AND PARTNERS' EQUITY		
Current liabilities:		
Accounts payable and drafts payable	$ 70.6	$ 105.5
Accounts payable to related party	1.1	4.3
Accrued gas, NGLs, condensate, and crude oil purchases	354.8	500.4
Fair value of derivative liabilities	14.4	21.8
Current maturities of long-term debt	—	399.8
Other current liabilities	201.7	246.7
Total current liabilities	642.6	1,278.5
Long-term debt, including $1,700.0 from affiliates	4,764.3	3,919.8
Asset retirement obligations	15.5	14.8
Other long-term liabilities	90.8	20.0
Deferred tax liability	44.5	42.4
Fair value of derivative liabilities	6.8	2.4
Redeemable non-controlling interest	5.2	9.3
Partners' equity:		
Common unitholders (144,358,720 and 353,117,434 units issued and outstanding, respectively)	1,681.2	2,460.8
Series B preferred unitholders (59,599,550 and 58,728,994 units issued and outstanding, respectively)	895.1	889.3
Series C preferred unitholders (400,000 units outstanding)	395.1	395.1
General partner interest (1,594,974 equivalent units outstanding)	216.6	231.2
Accumulated other comprehensive loss	(14.5)	(2.1)
Non-controlling interest	391.4	309.8
Total partners' equity	3,564.9	4,284.1
Commitments and contingencies (Note 13)		
Total liabilities and partners' equity	$ 9,134.6	$ 9,571.3

See accompanying notes to consolidated financial statements.

ENLINK MIDSTREAM PARTNERS, LP AND SUBSIDIARIES
Consolidated Statements of Operations
(In millions)

	Year Ended December 31,		
	2019	2018	2017
Revenues:			
Product sales	$ 5,030.1	$ 6,512.3	$ 4,358.4
Product sales—related parties	—	41.0	144.9
Midstream services	1,008.4	763.3	552.3
Midstream services—related parties	—	377.2	688.2
Gain (loss) on derivative activity	14.4	5.2	(4.2)
Total revenues	6,052.9	7,699.0	5,739.6
Operating costs and expenses:			
Cost of sales (1)	4,392.5	6,008.0	4,361.5
Operating expenses	467.1	453.4	418.7
General and administrative	139.2	130.2	123.5
(Gain) loss on disposition of assets	(1.9)	0.4	—
Depreciation and amortization	617.0	577.3	545.3
Impairments	198.2	365.8	17.1
Loss on secured term loan receivable	52.9	—	—
Gain on litigation settlement	—	—	(26.0)
Total operating costs and expenses	5,865.0	7,535.1	5,440.1
Operating income	187.9	163.9	299.5
Other income (expense):			
Interest expense, net of interest income (2)	(215.7)	(178.3)	(187.9)
Gain on extinguishment of debt	—	—	9.0
Income (loss) from unconsolidated affiliates	(16.8)	13.3	9.6
Other income	0.9	0.6	0.6
Total other expense	(231.6)	(164.4)	(168.7)
Income (loss) before non-controlling interest and income taxes	(43.7)	(0.5)	130.8
Income tax benefit (expense)	(2.5)	2.1	24.0
Net income (loss)	(46.2)	1.6	154.8
Net income attributable to non-controlling interest	8.1	2.1	1.1
Net income (loss) attributable to ENLK	$ (54.3)	$ (0.5)	$ 153.7

(1) Includes related party cost of sales of $21.7 million, $114.1 million, and $211.0 million for the years ended December 31, 2019, 2018, and 2017, respectively.
(2) Includes related party interest expense of $66.0 million for the year ended December 31, 2019.

See accompanying notes to consolidated financial statements.

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

	Year Ended December 31,		
	2019	2018	2017
Net income (loss)	$ (46.2)	$ 1.6	$ 154.8
Loss on designated cash flow hedge	(12.4)	—	(2.1)
Comprehensive income (loss)	(58.6)	1.6	152.7
Comprehensive income attributable to non-controlling interest	8.1	2.1	1.1
Comprehensive income (loss) attributable to ENLK	$ (66.7)	$ (0.5)	$ 151.6

See accompanying notes to consolidated financial statements.

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

	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	$	$	$	$
Balance, December 31, 2016	$ 3,461.8	342.9	$ 794.0	53.2	$ —	—	$203.6	1.6	$ —	$ 181.0	$ 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)	—	—	(26.9)	(653.2)	(0.6)
Contributions from non-controlling interests	—	—	—	—	—	—	—	—	—	126.4	126.4	—
Loss on designated cash flow hedge	—	—	—	—	—	—	—	—	(2.1)	—	(2.1)	—
Adjustment for acquisition of EOGP (Note 1)	48.4	—	—	—	—	—	—	—	—	(48.4)	—	—
Net income	17.9	—	86.0	—	6.7	—	43.1	—	—	1.1	154.8	—
Balance, December 31, 2017	3,108.6	349.7	864.1	57.1	395.1	0.4	206.6	1.6	(2.1)	233.2	4,805.5	4.6
Issuance of common units	46.1	2.6	—	—	—	—	—	—	—	—	46.1	—
Conversion of restricted units for common units, net of units withheld for taxes	(5.6)	0.8	—	—	—	—	—	—	—	—	(5.6)	—
Unit-based compensation	21.4	—	—	—	—	—	20.4	—	—	—	41.8	—
Distributions	(551.6)	—	(65.0)	1.6	(24.0)	—	(61.9)	—	—	(54.5)	(757.0)	—
Contributions from non-controlling interests	—	—	—	—	—	—	—	—	—	156.4	156.4	—
Fair value adjustment related to redeemable non-controlling interest	(4.1)	—	—	—	—	—	—	—	—	—	(4.1)	4.1
Adjustment for acquisition of EOGP (Note 1)	26.8	—	—	—	—	—	—	—	—	(26.8)	—	—
Net income (loss)	(180.8)	—	90.2	—	24.0	—	66.1	—	—	1.5	1.0	0.6
Balance, December 31, 2018	$ 2,460.8	353.1	$ 889.3	58.7	$395.1	0.4	$231.2	1.6	$ (2.1)	$ 309.8	$ 4,284.1	$ 9.3

See accompanying notes to consolidated financial statements.

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

	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	$	$	$	$
Balance, December 31, 2018	$ 2,460.8	353.1	$ 889.3	58.7	$ 395.1	0.4	$ 231.2	1.6	$ (2.1)	$ 309.8	$ 4,284.1	$ 9.3
Adoption of ASC 842	0.3	—	—	—	—	—	—	—	—	—	0.3	—
Balance, January 1, 2019	2,461.1	353.1	889.3	58.7	395.1	0.4	231.2	1.6	(2.1)	309.8	4,284.4	9.3
Conversion of restricted units for common units, net of units withheld for taxes	(2.8)	0.5	—	—	—	—	—	—	—	—	(2.8)	—
Unit-based compensation	1.4	—	—	—	—	—	37.0	—	—	—	38.4	—
Distributions	(667.0)	—	(67.4)	0.9	(24.0)	—	(15.6)	—	—	(23.8)	(797.8)	(0.3)
Contributions from non-controlling interests	—	—	—	—	—	—	—	—	—	97.5	97.5	—
Loss on designated cash flow hedge	—	—	—	—	—	—	—	—	(12.4)	—	(12.4)	—
Fair value adjustment related to redeemable non-controlling interest	4.0	—	—	—	—	—	—	—	—	—	4.0	(4.0)
Net income (loss)	(115.5)	—	73.2	—	24.0	—	(36.0)	—	—	7.9	(46.4)	0.2
Issuance of common units to ENLC for acquisition of EOGP	—	55.8	—	—	—	—	—	—	—	—	—	—
Conversion of ENLK common units into ENLC units	—	(265.0)	—	—	—	—	—	—	—	—	—	—
Balance, December 31, 2019	$ 1,681.2	144.4	$ 895.1	59.6	$ 395.1	0.4	$ 216.6	1.6	$ (14.5)	$ 391.4	$ 3,564.9	$ 5.2

See accompanying notes to consolidated financial statements.

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

	Year Ended December 31,		
	2019	2018	2017
Cash flows from operating activities:			
Net income (loss)	$ (46.2)	$ 1.6	$ 154.8
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Impairments	198.2	365.8	17.1
Depreciation and amortization	617.0	577.3	545.3
Loss on secured term loan receivable	52.9	—	—
Non-cash revenue from contract restructuring	—	(45.5)	—
Non-cash unit-based compensation	39.2	40.8	47.8
Deferred tax expense (benefit)	2.1	(3.9)	(26.6)
(Gain) loss on derivative activity recognized in net income (loss)	(14.4)	(5.2)	4.2
Cash settlements on derivatives	16.9	(7.0)	(11.2)
Gain on extinguishment of debt	—	—	(9.0)
Amortization of debt issue costs, net (premium) discount of notes and installment payable	4.9	4.0	29.1
Distribution of earnings from unconsolidated affiliates	16.5	15.8	13.3
(Income) loss from unconsolidated affiliates	16.8	(13.3)	(9.6)
Other operating activities	(4.1)	(2.2)	0.6
Changes in assets and liabilities:			
Accounts receivable, accrued revenue, and other	320.3	(114.6)	(189.5)
Natural gas and NGLs inventory, prepaid expenses, and other	12.7	(12.2)	(23.7)
Accounts payable, accrued product purchases, and other accrued liabilities	(248.3)	55.4	163.9
Net cash provided by operating activities	984.5	856.8	706.5
Cash flows from investing activities:			
Additions to property and equipment	(754.9)	(843.1)	(790.8)
Proceeds from sale of unconsolidated affiliate investment	—	—	189.7
Proceeds from sale of property	14.3	1.9	2.3
Investment in unconsolidated affiliates	—	(0.1)	(12.6)
Distribution from unconsolidated affiliates in excess of earnings	3.7	6.9	0.2
Other investing activities	(4.6)	8.1	0.4
Net cash used in investing activities	(741.5)	(826.3)	(610.8)
Cash flows from financing activities:			
Proceeds from borrowings	4,160.0	3,904.0	2,315.9
Payments on borrowings	(3,710.0)	(3,054.0)	(2,104.3)
Payment of installment payable for EOGP acquisition	—	(250.0)	(250.0)
Debt financing costs	(10.0)	(1.7)	(5.5)
Proceeds from issuance of common units	—	46.1	106.9
Proceeds from issuance of Series C Preferred Units	—	—	394.0
Distribution to common unitholders and to general partner	(682.6)	(613.5)	(604.8)
Distributions to Series B Preferred Unitholders	(67.4)	(65.0)	(15.9)
Distributions to Series C Preferred Unitholders	(24.0)	(24.0)	(5.6)
Distributions to non-controlling interests	(24.1)	(54.5)	(27.5)
Contributions by non-controlling interests, including contributions from ENLC of $66.2 million and $69.1 million for the years ended December 31, 2018 and 2017, respectively	97.5	156.4	126.4
Other financing activities	(4.5)	(5.6)	(6.1)
Net cash provided by (used in) financing activities	(265.1)	38.2	(76.5)
Net increase (decrease) in cash and cash equivalents	(22.1)	68.7	19.2
Cash and cash equivalents, beginning of period	99.5	30.8	11.6
Cash and cash equivalents, end of period	$ 77.4	$ 99.5	$ 30.8

See accompanying notes to consolidated financial statements.

(1) Organization and Summary of Significant Agreements

(a) Organization of Business

ENLK is a Delaware limited partnership formed in 2002. Our business activities are conducted through 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 a direct, wholly-owned subsidiary of ENLC. ENLC's units are traded on the NYSE under the symbol "ENLC." ENLC's managing member is a wholly-owned subsidiary of GIP.

EOGP Acquisition and Transfer of EOGP Interest

On January 7, 2016, EOGP, an indirect subsidiary of ENLK, completed its acquisition of 100% of the issued and outstanding membership interests of TOMPC LLC and TOM-STACK, LLC. As a result of the acquisition, the Operating Partnership acquired an 83.9% limited partner interest in EOGP, and ENLC acquired the remaining 16.1% limited partner interest in EOGP. On January 31, 2019, ENLC transferred its 16.1% limited partner interest in EOGP to the Operating Partnership in exchange for 55,827,221 ENLK common units, resulting in the Operating Partnership owning 100% of the limited partner interests in EOGP. This acquisition has been accounted for as an acquisition under common control under ASC 805, Business Combinations, resulting in the retrospective adjustment of our prior results. The "Adjustment for acquisition of EOGP (Note 1)" presented in the consolidated statements of changes in partners' equity represents the adjustment due to the recast to offset distributions paid to ENLC and contributions received from ENLC for its related ownership in EOGP.

Devon Transaction

In 2014, we completed a series of transactions with Devon pursuant to which Devon contributed certain subsidiaries and assets to us in exchange for a majority interest in us (the "Devon Transaction").

GIP Transaction

On July 18, 2018, subsidiaries of Devon closed a transaction to sell all of their equity interests in ENLK, ENLC, and the managing member of ENLC to GIP. As a result of the transaction:

- GIP, through GIP III Stetson I, L.P., acquired all of the equity interests held by subsidiaries of Devon in ENLK and the managing member of ENLC, which, as of the closing date, amounted to 100% of the outstanding limited liability company interests in the managing member of ENLC and approximately 23.1% of the outstanding limited partner interests in ENLK;
- GIP, through GIP III Stetson II, L.P., acquired all of the equity interests held by subsidiaries of Devon in ENLC, which, as of the closing date, amounted to approximately 63.8% of the outstanding limited liability company interests in ENLC; and
- Through this transaction, GIP acquired control of (i) the managing member of ENLC, (ii) ENLC, and (iii) ENLK, as a result of ENLC's ownership of our general partner.

Simplification of the Corporate Structure

On January 25, 2019, we completed the Merger, an internal reorganization pursuant to which ENLC owns all of the outstanding common units of ENLK. As a result of the Merger:

- Each issued and outstanding ENLK common unit (except for ENLK common units held by ENLC and its subsidiaries) was converted into 1.15 ENLC common units, which resulted in ENLC owning all of the remaining outstanding ENLK common units.
- Our general partner's incentive distribution rights in ENLK were eliminated.

- Certain terms of the Series B Preferred Units were modified pursuant to an amended partnership agreement of ENLK.See “Note 8—Partners' Capital” for additional information regarding the modified terms of the Series B Preferred Units.

- ENLC issued to Enfield, the current holder of the Series B Preferred Units, for no additional consideration, ENLC Class C Common Units equal to the number of Series B Preferred Units held by Enfield immediately prior to the effective time of the Merger, in order to provide Enfield with certain voting rights with respect to ENLC. ENLC also agreed to issue an additional ENLC Class C Common Unit to the applicable holder of each Series B Preferred Unit for each additional Series B Preferred Unit issued by ENLK in quarterly in-kind distributions. In addition, for each Series B Preferred Unit that is exchanged into an ENLC common unit, an ENLC Class C Common Unit will be canceled.

- The Series C Preferred Units and all of our then-existing senior notes continue to be issued and outstanding following the Merger.

- Each unit-based award issued and outstanding immediately prior to the effective time of the Merger under the GP Plan was converted into 1.15 awards with respect to ENLC common units with substantially similar terms as were in effect immediately prior to the effective time.

- Each unit-based award with performance-based vesting conditions issued and outstanding immediately prior to the effective time of the Merger under the GP Plan and the 2014 Plan was modified such that the performance metric for any then outstanding performance award relates (on a weighted average basis) to (i) the combined performance of ENLC and ENLK for periods preceding the effective time of the Merger and (ii) the performance of ENLC for periods on and after the effective time of the Merger.

- ENLC assumed the outstanding debt under the Term Loan and ENLK became a guarantor thereof. See “Note 6—Long-Term Debt” for additional information regarding the Term Loan.

- We refinanced our existing revolving credit facilities at ENLK and ENLC. In connection with the Merger,ENLC entered into the Consolidated Credit Facility, with respect to which ENLK is a guarantor. See “Note 6—Long-Term Debt” for additional information regarding the Consolidated Credit Facility.

(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, and selling NGLs; and
- gathering, transporting, stabilizing, storing, trans-loading, and selling crude oil and condensate, in addition to brinedisposal services.

Our midstream energy asset network includes approximately 12,000 miles of pipelines, 21 natural gas processing plants with approximately 5.3 Bcf/d of processing capacity, seven fractionators with approximately 290,000 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.

Our natural gas business includes connecting the wells of producers in our market areas to our gathering systems. Our gathering systems consist of networks of pipelines that collect natural gas from points at or 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, marketers, 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. 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 the gathering and transmission of crude oil and condensate via pipelines, barges, rail, and trucks, in addition to condensate stabilization and brine disposal. We also purchase crude oil and condensate from producers and other supply sources and sell that crude oil and condensate through our terminal facilities to various markets.

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 most of our transactions is the use of our assets to transport a product or provide a processed product to an end-user or marketer at the tailgate of the plant, pipeline, barge, truck, or rail terminal.

(2) Significant Accounting Policies

(a) Basis of Presentation

The accompanying consolidated financial statements have been prepared in accordance with GAAP for complete financial statements. Effective January 1, 2019, we changed our reportable operating segments to reflect how we currently make financial decisions and allocate resources, in connection with which certain reclassifications were made to the financial statements for prior periods to conform to current period presentation. The effect of these reclassifications had no impact on previously reported partners' equity or net income (loss). See "Note 14—Segment Information" for additional information regarding the change in reportable operating segments. All significant intercompany balances and transactions have been eliminated in consolidation.

(b) Management's Use of Estimates

The preparation of financial statements in accordance with 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 most of our transactions is the use of our assets to transport a product or provide a processed product to an end-user or marketer at the tailgate of the plant, pipeline, or barge, truck, or rail terminal. Revenues from both "Product sales" and "Midstream services" represent revenues from contracts with customers and are reflected on the consolidated statements of operations as follows:

- *Product sales*—Product 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.

Adoption of ASC 606

Effective January 1, 2018, we adopted ASC 606 using the modified retrospective method. ASC 606 replaced previous revenue recognition requirements in GAAP and requires 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 also requires 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.

Evaluation of Our Contractual Performance Obligations

In adopting ASC 606, we evaluated our contracts with customers that are within the scope of ASC 606. In accordance with the new revenue recognition framework introduced by ASC 606, we identified our performance obligations under our contracts with customers. These performance obligations include:

- promises to perform midstream services for our customers over a specified contractual term and/or for a specified volume of commodities; and

- promises to sell a specified volume of commodities to our customers.

The identification of performance obligations under our contracts requires a contract-by-contract evaluation of when control, including the economic benefit, of commodities transfers to and from us (if at all). This evaluation of control changed the way we account for certain transactions effective January 1, 2018, specifically those contracts in which there is both a commodity purchase and a midstream service. 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 do not consider these revenue-generating contracts for purposes of ASC 606. Based on the control determination, all contractually-stated fees that are deducted from our payments to producers or other suppliers for commodities purchased are reflected as a reduction in the cost of such commodity purchases. Alternatively, for contracts where control of commodities transfers to us after we perform our services, we consider these contracts to contain performance obligations for our services. Accordingly, we consider the satisfaction of these performance obligations as revenue-generating and recognize the fees received for satisfying them as midstream services revenues over time as 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 recognize these fees as midstream services revenues over time as we satisfy our performance obligations.

We also evaluate our contractual arrangements that contain a purchase and sale of commodities under the principal/agent provisions in ASC 606. For contracts where we possess control of the commodity and act as principal in the purchase and sale, we record product sales revenue at the price at which the commodities are sold, with a corresponding cost of sales equal to the cost of the commodities when purchased. For contracts in which we do not possess control of the commodity and are acting as an agent, our consolidated statements of operations only reflect midstream services revenues that we earn based on the fees contained in the applicable contract.

Based on our review of our performance obligations in our contracts with customers, we changed the consolidated statement of operations classification for certain transactions from revenue to cost of sales or from cost of sales to revenue. For the year ended December 31, 2018, the reclassification of revenues and cost of sales resulted in a net decrease in revenue of approximately $671.0 million, or 8.0%, compared to total revenues based on accounting prior to the adoption of ASC 606, with an equivalent net decrease in cost of sales. This change in accounting treatment had no impact on our operating income, net income, results of operations, financial condition, or cash flows.

Changes in Accounting Methodology for Certain Contracts

For NGL contracts in which we purchase raw mix NGLs and subsequently transport, fractionate, and market the NGLs, we accounted for these contracts prior to the adoption of ASC 606 as revenue-generating contracts in which the fees we earned for our services were recorded as midstream services revenue on the consolidated statements of operations. As a result of the adoption of ASC 606, we determined that the control, including the economic benefit, of commodities has passed to us once the raw mix NGLs have been purchased from the customer. Therefore, we now consider the contractually-stated fees to serve as pricing mechanisms that reduce the cost of such commodity purchased upon receipt of the raw mix NGLs, rather than being recorded as midstream services revenue. Upon sale of the NGLs to a third-party customer, we record product sales revenue at the price at which the commodities are sold, with a corresponding cost of sales equal to the cost of the commodities purchased.

For our crude oil and condensate service contracts in which we purchase the commodity, we utilize a similar approach under ASC 606 as outlined above for NGL contracts. This treatment is consistent with our accounting for crude oil and condensate service contracts prior to the adoption of ASC 606.

For our natural gas gathering and processing contracts in which we perform midstream services and also purchase the natural gas, we accounted for these contracts prior to the adoption of ASC 606 as revenue-generating contracts in which all contractually-stated fees earned for our gathering and processing services were recorded as midstream services revenue on the statements of operations. As a result of the adoption of ASC 606, we must determine if economic control of the commodities has passed from the producer to us before or after we perform our services (if at all). Control is assessed on a contract-by-contract basis by analyzing each contract’s provisions, which can include provisions for: the customer to take its residue gas and/or NGLs in-kind; fixed or actual NGL or keep-whole recovery; commodity purchase prices at weighted average sales price or market index-based pricing; and various other contract-specific considerations. Based on this control assessment, our gathering and processing contracts fall into two primary categories:

- For gathering and processing contracts in which there is a commodity purchase and analysis of the contract provisions indicates that control, including the economic benefit, of the natural gas passes to us when the natural gas is brought into our system, we do not consider these contracts to contain performance obligations for our services. As control of the natural gas passes to us prior to performing our gathering and processing services, we are, in effect, performing our services for our own benefit. Based on this control determination, we consider the contractually-stated fees to serve as pricing mechanisms that reduce the cost of such commodity purchased upon receipt of the natural gas, rather than being recorded as midstream services revenue. Upon sale of the residue gas and/or NGLs to a third-party customer, we record product sales revenue at the price at which the commodities are sold, with a corresponding cost of sales equal to the cost of the commodities purchased.

- For gathering and processing contracts in which there is a commodity purchase and analysis of the contract provisions indicates that control, including the economic benefit, of the natural gas does not pass to us until after the natural gas has been gathered and processed, we consider these contracts to contain performance obligations for our services. Accordingly, we consider the satisfaction of these performance obligations as revenue-generating, and we recognize the fees received for satisfying these performance obligations as midstream services revenues over time as we satisfy our performance obligations.

For midstream service contracts related to NGL, crude oil, or natural gas gathering and processing in which there is no commodity purchase or control of the commodity never passes to us and we simply earn a fee for our services, we consider these contracts to contain performance obligations for our services. Accordingly, we consider the satisfaction of these performance obligations as revenue-generating, and we recognize the fees received for satisfying these performance obligations as midstream services revenue over time as we satisfy our performance obligations. This treatment is consistent with our accounting for these contracts prior to the adoption of ASC 606.

For our natural gas transmission contracts, we determined that control of the natural gas never transfers to us and we simply earn a fee for our services. Therefore, we recognize these fees as midstream services revenue over time as we satisfy our performance obligations. This treatment is consistent with our accounting for natural gas transmission contracts prior to the adoption of ASC 606.

We also evaluate our commodity marketing contracts, under which we purchase and sell commodities in connection with our gas, NGL, and crude and condensate midstream services, pursuant to ASC 606, including the principal/agent provisions.

For contracts in which we possess control of the commodity and act as principal in the purchase and sale of commodities, we record product sales revenue at the price at which the commodities are sold, with a corresponding cost of sales equal to the cost of the commodities when purchased. For contracts in which we do not possess control of the commodity and are acting as agent, our consolidated statements of operations only reflect midstream services revenues that we earn based on the fees contained in the applicable contract. This treatment is consistent with our accounting for our commodity marketing contracts prior to the adoption of ASC 606.

Satisfaction of Performance Obligations and Recognition of Revenue

While ASC 606 alters the line item on which certain amounts are recorded on the consolidated statements of operations, ASC 606 did not significantly affect the timing of income and expense recognition on the consolidated statements of operations. Specifically, for our commodity sales contracts, we satisfy our performance obligations at the point in time at which the commodity transfers from us to the customer. This transfer pattern aligns with our billing methodology. Therefore, we recognize product sales revenue at the time the commodity is delivered and in the amount to which we have the right to invoice the customer, which is consistent with our accounting prior to the adoption of ASC 606. For our midstream service contracts that contain revenue-generating performance obligations, we satisfy our performance obligations over time as we perform the midstream service and as the customer receives the benefit of these services over the term of the contract. As permitted by ASC 606, we are utilizing the practical expedient that allows an entity to recognize revenue in the amount to which the entity has a right to invoice, since we have a right to consideration from our customer in an amount that corresponds directly with the value to the customer of our performance completed to date. Accordingly, we continue to recognize revenue over time as our midstream services are performed. Therefore, ASC 606 does not significantly affect the timing of revenue and expense recognition on our consolidated statements of operations, and no cumulative effect adjustment was made to the balance of equity upon our adoption of ASC 606.

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. We typically receive payment for invoiced amounts within one month, depending on the terms of the contract. We account for taxes collected from customers attributable to revenue transactions and remitted to government authorities on a net basis (excluded from revenues).

Minimum Volume Commitments and Firm Transportation Contracts

Certain of our gathering and processing agreements provide for quarterly or annual MVCs. Under these agreements, our customers or suppliers agree to ship and/or process a minimum volume of product on our systems over an agreed time period. If a customer or supplier 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 product volumes and the MVC for that period. Some of these agreements also contain make-up right provisions that allow a customer or supplier 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. Deficiency fee revenue is included in midstream services revenue.

For our firm transportation contracts, we transport commodities owned by others for a stated monthly fee for a specified monthly quantity with an additional fee based on actual volumes. We include transportation fees from firm transportation contracts in our midstream services revenue.

The following table summarizes the contractually committed fees that we expect to recognize in our consolidated statements of operations, in either revenue or reductions to cost of sales, from MVC and firm transportation contractual provisions. All amounts in the table below are determined using the contractually-stated MVC or firm transportation volumes specified for each period multiplied by the relevant deficiency or reservation fee. Actual amounts could differ due to the timing of revenue recognition or reductions to cost of sales resulting from make-up right provisions included in our agreements, as well as due to nonpayment or nonperformance by our customers. These fees do not represent the shortfall amounts we expect to collect under our MVC contracts, as we generally do not expect volume shortfalls to equal the full amount of the contractual MVCs during these periods. For example, for the year ended December 31, 2019, we had contractual commitments of $154.0 million under our MVC contracts and recorded $19.7 million of revenue due to volume shortfalls.

MVC and Firm Transportation Commitments (in millions) (1)		
2020	$	262.7
2021		111.0
2022		97.6
2023		92.7
2024		81.3
Thereafter		158.2
Total	$	803.5

(1) Amounts do not represent expected shortfall under these commitments.

Contributions in Aid of Construction

The adoption of ASC 606 also alters how we account for contributions in aid of construction (“CIAC”). CIAC payments are lump sum payments from third parties to reimburse us for capital expenditures related to the construction of our operating assets and, in most cases, the connection of these operating assets to the third party’s assets. CIAC payments can be paid to us prior to the commencement of construction activities, during construction, or after construction has been completed. Prior to adoption of ASC 606 and in accordance with ASC 980, *Regulated Operations* (“ASC 980”), and the FERC Uniform System of Accounts, we reduced the balance of the related property and equipment by the amount of CIAC payments received. In doing so, CIAC payments previously affected the consolidated statements of operations through reduced depreciation expense over the useful lives of the related property and equipment. Upon adoption of ASC 606, we initially recognize CIAC payments received from customers as deferred revenue, which will be subsequently amortized into revenue over the term of the underlying operational contract. For CIAC payments from noncustomers and for payments related to the construction of regulated operating assets, we continue to reduce the balance of the related property and equipment in accordance with ASC 980 and the FERC Uniform System of Accounts. This change in our CIAC accounting policy was not material to our financial statements for the year ended December 31, 2018.

Disaggregation of Revenue and Presentation of Prior Periods

Based on the disclosure requirements of ASC 606, we are presenting revenues disaggregated based on the type of good or service in order to more fully depict the nature of our revenues. See “Note 14—Segment Information” for the revenue disaggregation information included in the segment information table for the years ended December 31, 2019 and 2018. As we adopted ASC 606 using the modified retrospective method, only the consolidated statement of operations and revenue disaggregation information for the years ended December 31, 2019 and 2018 are presented to conform to ASC 606 accounting and disclosure requirements. Prior periods presented in the consolidated financial statements and accompanying notes were not restated in accordance with ASC 606.

(d) Secured Term Loan Receivable

In late May 2019, White Star, the counterparty to our $58.0 million second lien secured term loan receivable, filed for reorganization under Chapter 11 of the U.S. Bankruptcy Code. Under the original term loan agreement executed in May 2018, White Star was scheduled to make an installment payment of $19.5 million in April 2019. In November 2018 and again in February 2019, we amended the installment payment terms with the result that the single 2019 installment payment was split into two payments of $9.75 million in May 2019 and $10.75 million in October 2019. White Star defaulted on its May 2019 installment payment prior to filing for reorganization under Chapter 11 of the U.S. Bankruptcy Code. In November 2019, White Star sold its assets and we did not recover any amounts then owed to us under the second lien secured term loan. As a result, we have recorded a $52.9 million loss in our consolidated statement of operations for the year ended December 31, 2019, which represents a full write-down of the second lien secured term loan.

(e) 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 $5.7 million and $12.4 million at December 31, 2019 and 2018, respectively, which approximate the fair value of these imbalances. We had imbalance receivables of$6.4 million and $10.4 million at December 31, 2019 and 2018, 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.

(f) Cash and Cash Equivalents

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

(g) 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. We record deferred tax assets and liabilities on a net basis on the consolidated balance sheets, with deferred tax assets included in "Other assets, net" and deferred tax liabilities included in "Deferred tax liability, net."

(h) 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.

(i) 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, net of accumulated depreciation are as follows (in millions):

	Year Ended December 31,	
	2019	2018
Transmission assets	$ 1,376.5	$ 1,329.4
Gathering systems	4,856.5	4,410.5
Gas processing plants	3,862.2	3,590.5
Other property and equipment	188.0	171.7
Construction in process	216.7	312.0
Property and equipment	10,499.9	9,814.1
Accumulated depreciation	(3,418.6)	(2,967.4)
Property and equipment, net of accumulated depreciation	$ 7,081.3	$ 6,846.7

Depreciation Expense. 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 $490.7 million, $453.8 million, and $418.2 million was recorded for the years ended December 31, 2019, 2018, and 2017, 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, 2019, we disposed of assets with a net book value of $12.4 million, and these dispositions primarily related to the sale of certain non-core assets. This decrease in book value was offset by $14.3 million of proceeds from the sale of property, resulting in a $1.9 million gain on disposition of assets in the consolidated statement of operations for the year ended December 31, 2019.

For the year ended December 31, 2018, we disposed of assets with a net book value of $2.1 million. These dispositions primarily related to vehicle retirements and retirements due to compressor fire damage. This decrease in book value was offset by $1.7 million of proceeds from the sale of property, resulting in $0.4 million loss on disposition of assets in the consolidated statement of operations for the year ended December 31, 2018.

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 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.

Impairment Review. In accordance with ASC 360, *Property, Plant, and Equipment*, we evaluate long-lived assets of identifiable business activities for potential impairment annually in the fourth quarter, and 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 is recognized equal to the excess of the asset's carrying value over its fair value, which is based on inputs that are not observable in the market, and thus represent Level 3 inputs.

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, 2019, we recognized a $7.9 million impairment on property and equipment related to certain decommissioned and removed non-core assets.

For the year ended December 31, 2018, we determined that the undiscounted cash flows for two of our assets were not in excess of their carrying values. We estimated the fair values of these assets and determined that their fair values were not in excess of their carrying values, which resulted in impairments on property and equipment of $24.6 million related to certain non-core natural gas pipeline assets in the Louisiana segment and $109.2 million related to non-core crude pipeline assets in the Permian segment.

For the year ended December 31, 2017, we recognized a $17.1 million impairment on property and equipment, which related to the carrying values of rights-of-way that we are no longer using and an abandoned brine disposal well.

(j) Comprehensive Income (Loss)

Comprehensive income (loss) is composed of net income (loss) and 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 additional information about the effect of financial instruments on comprehensive income (loss), see “Note 11—Derivatives.”

(k) 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.

We recognized a $31.4 million loss for the year ended December 31, 2019 related to the impairment of the carrying value of the Cedar Cove JV, as we determined that the carrying value of our investment was not recoverable based on the forecasted cash flows from the Cedar Cove JV.

For additional information, see “Note 9—Investment in Unconsolidated Affiliates.”

(l) Non-controlling Interests

We account for investments where we control the investment using the consolidation method of accounting. Under this method, we consolidate all the assets and liabilities of an investment on our consolidated balance sheets and record non-controlling interest for the portion of the investment that we do not own. We include all of an investment’s results of operations on our consolidated statements of operations and record income attributable to non-controlling interests for the portion of the investment that we do not own.

Our non-controlling interests for the years ended December 31, 2019, 2018, and 2017 relate to NGP’s 49.9% ownership of the Delaware Basin JV, Marathon Petroleum Corporation’s 50.0% ownership interest in the Ascension JV, and other minor non-controlling interests.

(m) 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 3—Goodwill and Intangible Assets."

(n) 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 five to twenty years. For additional information regarding our intangible assets, including our assessment of intangible assets for impairment, see "Note 3—Goodwill and Intangible Assets."

(o) 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.

(p) Other Current Liabilities

Other current liabilities included a liability related to an onerous performance obligation of $9.0 million as of December 31, 2018. We had one delivery contract that required us to deliver a specified volume of gas each month at an indexed base price that ended June 2019. We realized a loss on the delivery of gas under this contract each month based on current prices. The liability was reduced each month as delivery was made over the life of the contract with an offsetting reduction in purchased gas costs.

(q) 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. 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.

In April 2019, we entered into an $850.0 million interest rate swap with ENLC, which mirrored the terms of ENLC's interest rate swap with a third party, to manage the interest rate risk associated with our floating-rate, LIBOR-based borrowings. Under this arrangement, we pay a fixed interest rate of 2.27825% in exchange for LIBOR-based variable interest through December 2021. Assets or liabilities related to this interest rate swap contract are included in the fair value of derivative assets and liabilities on the consolidated balance sheets, and the change in fair value of this contract is recorded net as gain or loss on designated cash flow hedges on the consolidated statements of comprehensive income. Monthly, upon settlement, we reclassify the gain or loss associated with the interest rate swap into interest expense from accumulated other comprehensive income (loss). There is no ineffectiveness related to this hedge.

In May 2017, we entered into an interest rate swap in connection with the issuance of our 2047 Notes. Upon settlement of the interest rate swap in May 2017, we recorded the associated $2.2 million settlement loss in accumulated comprehensive loss on the consolidated balance sheets. We 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. For additional information, see "Note 11—Derivatives."

(r) 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 significant customers discussed below, since our customers represent a broad and diverse group of energy marketers and end users.

The following customers individually represented greater than 10% of our consolidated revenues. These customers represent a significant percentage of revenues, and the loss of the customer would have a material adverse impact on our results of operations because the revenues and gross operating margin received from transactions with these customers is material to us. No other customers represented greater than 10% of our consolidated revenues.

	Year Ended December 31,		
	2019	2018	2017
Devon	10.5%	10.4%	14.4%
Dow Hydrocarbons and Resources LLC	10.0%	11.1%	11.2%
Marathon Petroleum Corporation	13.8%	11.5%	(1)

(1) Consolidated revenues for Marathon Petroleum Corporation did not exceed 10% of our consolidated revenues for the year ended December 31, 2017.

We continually monitor and review the credit exposure of our counter-parties based on various credit quality indicators and metrics. We obtain letters of credit or other appropriate security 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 and we do not expect to experience significant levels of default on our trade accounts receivable. We had a reserve for uncollectible receivables of $0.5 million and $0.3 million as of December 31, 2019 and 2018, respectively.

(s) 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. For the years ended December 31, 2019, 2018, and 2017, environmental expenditures were not material.

(t) 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"). 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 ENLK. For additional information, see "Note 10—Employee Incentive Plans."

(u) 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. Legal costs incurred in connection with a loss contingency are expensed as incurred. For additional information, see "Note 13—Commitments and Contingencies."

(v) Debt Issuance Costs

Costs incurred in connection with the issuance of long-term debt are deferred and amortized into interest expense using the straight-line method 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 $29.8 million and $24.3 million as of December 31, 2019 and 2018, respectively, are included in "Long-term debt" or "Current maturities of long-term debt," as applicable, on the consolidated balance sheets as a direct reduction from the carrying amount of the debt.

(w) 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).

(x) Adopted Accounting Standards

Effective January 1, 2019, we adopted ASC 842, Leases, using the modified retrospective approach whereby we recognized leases on our consolidated balance sheet by recording a right-of-use asset and lease liability. We applied certain practical expedients that were allowed in the adoption of ASC 842, including not reassessing existing contracts for lease arrangements, not reassessing existing lease classification, not recording a right-of-use asset or lease liability for leases of twelve months or less, and not separating lease and non-lease components of a lease arrangement. In connection with the adoption of ASC 842 in January 2019, we recorded a lease liability of $97.6 million, a right-of-use asset of $75.3 million, and a reduction of $22.6 million in other liabilities previously recorded related to lease incentives. For additional information about our adoption of ASC 842, refer to "Note 5—Leases."

(y) Accounting Standards to be Adopted in Future Periods

On August 29, 2018, the FASB issued ASU 2018-15, Customer's Accounting for Implementation Costs Incurred in a Cloud Computing Arrangement That Is a Service Contract ("ASU 2018-15"), which amends ASC 350-40, Internal-Use Software ("ASC 350-40") to address a customer's accounting for implementation costs incurred in a cloud computing arrangement that is a service contract. ASU 2018-15 aligns the accounting for costs incurred to implement a cloud computing arrangement that is a service arrangement with the guidance on capitalizing costs associated with developing or obtaining internal-use software. Specifically, the ASU amends ASC 350-40 to include in its scope implementation costs of a cloud computing arrangement that is a service contract and clarifies that a customer should apply ASC 350-40 to determine which implementation costs should be capitalized in a cloud computing arrangement that is considered a service contract. We do not believe ASU 2018-15 will have a material impact on our financial statements, except to the extent future costs incurred in a cloud computing arrangement are capitalizable, the corresponding amortization will be included in "Operating expenses" or "General and administrative" in the consolidated statements of operations, rather than "Depreciation and amortization." We will adopt ASU 2018-15 prospectively effective January 1, 2020.

(3) 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. 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 cash flow multiples, and estimated future cash flows, including volume and price forecasts, capital expenditures, 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.

The table below provides a summary of our change in carrying amount of goodwill by segment (in millions) for the years ended December 31, 2019 and 2018, by assigned reporting unit. For the year ended December 31, 2017, there were no changes to the carrying amounts of goodwill.

	Permian	North Texas	Oklahoma	Louisiana	Corporate	Totals
Year Ended December 31, 2019						
Balance, beginning of period	$ —	$ —	$ 190.3	$ —	$ —	$ 190.3
Impairment	—	—	(190.3)	—	—	(190.3)
Balance, end of period	$ —	$ —	$ —	$ —	$ —	$ —

	Permian	North Texas	Oklahoma	Louisiana	Corporate	Totals
Year Ended December 31, 2018						
Balance, beginning of period	$ 29.3	$ 202.7	$ 190.3	$ —	$ —	$ 422.3
Impairment	(29.3)	(202.7)	—	—	—	(232.0)
Balance, end of period	$ —	$ —	$ 190.3	$ —	$ —	$ 190.3

Goodwill Impairment Analysis for the Year Ended December 31, 2019

During the fourth quarter of 2019, we performed a quantitative analysis as of October 31, 2019 for our annual goodwill impairment test. Subsequent to October 31, 2019, we determined that due to a significant decline in ENLC's common unit price and the expected reduction in ENLC's cash distribution paid to common unitholders, which was announced in January 2020, a change in circumstances had occurred that warranted an additional quantitative impairment test. We recorded a goodwill impairment loss of $190.3 million on our Oklahoma reporting unit. This amount is included in impairments in the consolidated statement of operations for the year ended December 31, 2019.

Goodwill Impairment Analysis for the Year Ended December 31, 2018

During our annual goodwill impairment test for 2018, which was performed as of October 31, 2018, we determined, based upon our qualitative assessment, that no impairments of goodwill were required as of that date. However, subsequent to October 31, 2018, we determined that due to a significant decline in our unit price, a change in circumstances had occurred that warranted a quantitative impairment test. Based on this triggering event, we performed a quantitative goodwill impairment analysis as of December 31, 2018. Based on this analysis, a goodwill impairment loss for our Permian and North Texas reporting units in the amounts of $29.3 million and $202.7 million, respectively, was recognized in the fourth quarter of 2018 and is included in impairments in the consolidated statement of operations for the year ended December 31, 2018.

We concluded that the fair value of our Oklahoma and Corporate reporting units exceeded their carrying values, and the amounts of goodwill disclosed on the consolidated balance sheet associated with these reporting units were recoverable.

Therefore, no goodwill impairment was identified or recorded for these reporting units as a result of our quantitative impairment test.

Goodwill 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.

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 5 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, 2019			
Customer relationships, beginning of period	$ 1,795.8	$ (422.2)	$ 1,373.6
Amortization expense	—	(123.7)	(123.7)
Customer relationships, end of period	$ 1,795.8	$ (545.9)	$ 1,249.9
Year Ended December 31, 2018			
Customer relationships, beginning of period	$ 1,795.8	$ (298.7)	$ 1,497.1
Amortization expense	—	(123.5)	(123.5)
Customer relationships, end of period	$ 1,795.8	$ (422.2)	$ 1,373.6
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

For the years ended December 31, 2019, 2018, and 2017, we reviewed our various assets groups for impairment during our annual impairment review process and determined that no impairment of our intangible assets occurred. We utilized Level 3 fair value measurements in our impairment analysis, which included cash flow assumptions consistent with those utilized in our goodwill impairment analysis.

The weighted average amortization period for intangible assets is 15.0 years. Amortization expense was $123.7 million, $123.5 million, and $127.1 million for the years ended December 31, 2019, 2018, and 2017, respectively.

The following table summarizes our estimated aggregate amortization expense for the next five years and thereafter (in millions):

2020	$ 123.7
2021	123.7
2022	123.7
2023	123.6
2024	123.4
Thereafter	631.8
Total	$ 1,249.9

(4) Related Party Transactions

(a) Transactions with ENLC

Simplification of the Corporate Structure. On January 25, 2019, we completed the Merger, an internal reorganization pursuant to which ENLC owns all of the outstanding common units of ENLK. See “Note 1—Organization and Summary of Significant Agreements” for more information on the Merger and related transactions.

Transfer of EOGP Interest. On January 31, 2019, ENLC transferred its16.1% limited partner interest in EOGP to the Operating Partnership in exchange for55,827,221 ENLK common units, resulting in the Operating Partnership owning 100% of the limited partner interests in EOGP.See “Note 1—Organization and Summary of Significant Agreements” for more information on the Merger and related transactions.

ENLC paid us $26.6 million and $48.4 million for its interest in EOGP’s capital expenditures for the years ended December 31, 2018 and 2017, respectively.ENLC paid its contribution for EOGP’s capital expenditures to ENLK monthly, net of EOGP’s adjusted EBITDA distributable to ENLC, which was defined as earnings before depreciation and amortization and provision for income taxes and included allocated expenses from us.

ENLC paid us $2.5 million and $2.4 million as reimbursement during the years ended December 31, 2018 and 2017,respectively, to cover its portion of administrative and compensation costs for officers and employees that performed services for ENLC. Officers and employees that performed services for ENLC provided 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) was allocated to ENLC for reimbursement based on these estimates. In addition, an administrative burden was 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. Subsequent to the closing of the Merger, ENLC no longer is allocated these administrative and compensation costs.

Related Party Debt. Related party debt includes borrowings under the Consolidated Credit Facility, the Term Loan, and ENLC’s5.375% senior unsecured notes due 2029 to fund the operations and growth capital expenditures of ENLK through a related party arrangement with ENLC. See “Note 6—Long-Term Debt” for more information on this arrangement.

We had accounts receivable balances related to transactions with ENLC of$18.1 million and $1.4 million at December 31, 2019 and December 31, 2018, respectively.

(b) Transactions with Devon

On July 18, 2018, subsidiaries of Devon sold all of their equity interests inENLK, ENLC, and the managing member of ENLC to GIP for aggregate consideration of $3.125 billion. Accordingly, Devon is no longer an affiliate of ENLK or ENLC. The sale did not affect our commercial arrangements with Devon, except that Devon agreed to extend through 2029 certain existing fixed-fee gathering and processing contracts related to the Bridgeport plant in North Texas and the Cana plant in Oklahoma. See “Note 1—Organization and Summary of Significant Agreements” for additional information regarding the GIP Transaction. Prior to July 18, 2018, revenues from transactions with Devon are included in “Product sales—related parties” or “Midstream services—related parties” in the consolidated statement of operations. Revenues from transactions with Devon after July 18, 2018 are included in “Product sales” or “Midstream services” in the consolidated statement of operations. For the years ended December 31, 2018 and 2017, related party revenues from Devon accounted for5.4% and 14.4% of our revenues, respectively.

Gathering and Processing Agreements with Devon

On January 1, 2014, we entered into10-year gathering and processing agreements with Devon to provide 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 our gathering and processing systems in the Barnett, Cana-Woodford, and Arkoma-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 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 our gathering systems in the Barnett, Cana-Woodford, and Arkoma-Woodford Shales during each calendar quarter. From January 1, 2018 to July 18, 2018 and for the year ended December 31, 2017, we recognized $321.3 million and $615.5 million of revenue, respectively, under these agreements. Included in these amounts of revenue recognized is revenue from MVCs attributable to Devon of $50.8 million from January 1, 2018 to July 18, 2018 and $81.9 million for the year ended December 31, 2017. Devon is entitled to firm service, meaning that if capacity on a system is curtailed or reduced, or capacity is otherwise insufficient, we 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 we are paid a specified fee per MMBtu for natural gas gathered on our 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.

EOGP Agreement with Devon

In January 2016, in connection with the acquisition of EOGP, we acquired a gas gathering and processing agreement with Devon Energy Production Company, L.P. (“DEPC”) pursuant to which EOGP provides gathering, treating, compression, dehydration, stabilization, processing, and fractionation services, as applicable, for natural gas delivered by DEPC. The agreement had an MVC that remained in place during each calendar quarter for four years and has an overall term of approximately 15 years. Additionally, the agreement provides EOGP 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 $77.6 million and $100.4 million of our combined revenues from January 1, 2018 to July 18, 2018 and for the year ended December 31, 2017, respectively.

Other Commercial Relationships with Devon

As noted above, we continue to maintain a customer relationship with Devon 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. 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 comprised $66.6 million and $78.0 million of our combined revenue from January 1, 2018 to July 18, 2018 and for the year ended December 31, 2017, respectively.

VEX Transportation Agreement

In connection with our acquisition of the VEX assets from Devon, we were party to a five-year transportation services agreement with Devon pursuant to which we provided transportation services to Devon on the VEX pipeline. This agreement included a five-year MVC with Devon. The MVC was executed in June 2014 and expired June 2019. This agreement accounted for approximately $3.5 million and $17.8 million of service revenues from January 1, 2018 to July 18, 2018 and for the year ended December 31, 2017, respectively.

Acacia Transportation Agreement

We entered into an agreement with a wholly-owned subsidiary of Devon pursuant to which we provide transportation services to Devon on our Acacia pipeline in North Texas. This agreement accounted for approximately $4.9 million and $13.8 million of our combined revenues from January 1, 2018 to July 18, 2018 and for the year ended December 31, 2017, respectively.

(c) Transactions with Cedar Cove JV

For the years ended December 31, 2018 and December 31, 2017, we recorded service revenue of $0.5 million and $5.4 million, respectively, that is recorded as “Midstream services—related parties” on the consolidated statements of operations. Additionally, for the years ended December 31, 2019, 2018, and 2017, we recorded cost of sales of $21.7 million, $44.1 million, $30.6 million, respectively, related to our purchase of residue gas and NGLs from the Cedar Cove JV subsequent to processing at our Central Oklahoma processing facilities. We had no accounts receivable balance related to transactions with the Cedar Cove JV at December 31, 2019 and $0.7 million at December 31, 2018. We had an accounts payable balance related to transactions with the Cedar Cove JV of $1.1 million and $4.3 million at December 31, 2019 and 2018, respectively.

(d) Tax Sharing Agreement

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. From January 1, 2018 to July 18, 2018 and for the year ended December 31, 2017 we incurred approximately $0.4 million and $1.2 million, respectively, in taxes that are subject to the tax sharing agreement. Effective July 18, 2018, ENLK, ENLC, and Devon signed a supplemental agreement reaffirming terms of the tax sharing agreement for tax periods ending July 18, 2018 and prior.

Management believes the foregoing transactions with related parties were executed on terms that are fair and reasonable to us. The amounts related to related party transactions are specified in the accompanying consolidated financial statements.

(5) Leases

Effective with the adoption of ASC 842 in January 2019, we evaluate new contracts at inception to determine if the contract conveys the right to control the use of an identified asset for a period of time in exchange for periodic payments. A lease exists if we obtain substantially all of the economic benefits of an asset, and we have the right to direct the use of that asset. When a lease exists, we record a right-of-use asset that represents our right to use the asset over the lease term and a lease liability that represents our obligation to make payments over the lease term. Lease liabilities are recorded at the sum of future lease payments discounted by the collateralized rate we could obtain to lease a similar asset over a similar period, and right-of-use assets are recorded equal to the corresponding lease liability, plus any prepaid or direct costs incurred to enter the lease, less the cost of any incentives received from the lessor. The majority of our leases are for the following types of assets:

- *Office space.* Our primary offices are in Dallas, Houston, and Midland, with smaller offices in other locations near our assets. Our office leases are long-term in nature and represent $60.0 million of our lease liability and $39.8 million of our right-of-use asset as of December 31, 2019. These office leases typically include variable lease costs related to utility expenses, which are determined based on our pro-rata share of the building expenses each month and expensed as incurred.

- *Compression and other field equipment.* We pay third parties to provide compressors or other field equipment for our assets. Under these agreements, a third party installs and operates compressor units based on specifications set by us to meet our compression needs at specific locations. While the third party determines which compressors to install and operates and maintains the units, we have the right to control the use of the compressors and are the sole economic beneficiary of the identified assets. These agreements are typically for an initial term of one to three years but will automatically renew from month to month until canceled by us or the lessor. Compression and other field equipment rentals represent $27.1 million of our lease liability and $27.1 million of our right-of-use asset as of December 31, 2019. Under certain agreements, we may incur variable lease costs related to incidental services provided by the equipment lessor, which are expensed as incurred.

- *Office equipment.* We rent office equipment for a monthly fee. These leases are typically for several years and represent $0.6 million of our lease liability and $0.6 million of our right-of-use asset as of December 31, 2019.

- *Land and land easements.* We make periodic payments to lease land or to have access to our assets. Land leases and easements are typically long-term to match the expected useful life of the corresponding asset and represent $15.3 million of our lease liability and $12.9 million of our right-of-use asset as of December 31, 2019.

Lease balances are recorded on the consolidated balance sheets as follows (in millions):

		December 31, 2019
Operating leases:		
Other assets, net	$	80.4
Other current liabilities	$	21.1
Other long-term liabilities	$	81.9

Other lease information	
Weighted-average remaining lease term—Operating leases	10.6 years
Weighted-average discount rate—Operating leases	5.1%

Certain of our lease agreements have options to extend the lease for a certain period after the expiration of the initial term. We recognize the cost of a lease over the expected total term of the lease, including optional renewal periods that we can reasonably expect to exercise. We do not have material obligations whereby we guarantee a residual value on assets we lease, nor do our lease agreements impose restrictions or covenants that could affect our ability to make distributions.

Lease expense is recognized on the consolidated statements of operations as “Operating expenses” and “General and administrative” depending on the nature of the leased asset. The components of total lease expense are as follows (in millions):

		Year Ended December 31, 2019
Finance lease expense:		
Amortization of right-of-use asset	$	5.2
Interest on lease liability		0.1
Operating lease expense:		
Long-term operating lease expense		28.7
Short-term lease expense		32.0
Variable lease expense		7.7
Total lease expense	$	68.4

Other information about our leases is presented below (in millions):

		Year Ended December 31, 2019
Supplemental cash flow information:		
Cash payments for finance leases included in cash flows from financing activities	$	1.2
Cash payments for operating leases included in cash flows from operating activities	$	29.8
Right-of-use assets obtained in exchange for operating lease liabilities	$	104.1

The following table summarizes the maturity of our lease liability as ofDecember 31, 2019 (in millions):

	Total	2020	2021	2022	2023	2024	Thereafter
Undiscounted operating lease liability	$ 141.2	$ 25.0	$ 18.7	$ 11.7	$ 9.7	$ 9.1	$ 67.0
Reduction due to present value	(38.2)	(4.7)	(3.9)	(3.4)	(3.1)	(2.7)	(20.4)
Operating lease liability	$ 103.0	$ 20.3	$ 14.8	$ 8.3	$ 6.6	$ 6.4	$ 46.6

(6) Long-Term Debt

As of December 31, 2019 and 2018, long-term debt consisted of the following (in millions):

	December 31, 2019			December 31, 2018		
	Outstanding Principal	Premium (Discount)	Long-Term Debt	Outstanding Principal	Premium (Discount)	Long-Term Debt
Related party debt	$ 1,700.0	$ —	$ 1,700.0	$ —	$ —	$ —
Term Loan due 2021 (1)	—	—	—	850.0	—	850.0
2.70% Senior unsecured notes due 2019 (2)	—	—	—	400.0	—	400.0
4.40% Senior unsecured notes due 2024	550.0	1.5	551.5	550.0	1.8	551.8
4.15% Senior unsecured notes due 2025	750.0	(0.7)	749.3	750.0	(0.9)	749.1
4.85% Senior unsecured notes due 2026	500.0	(0.5)	499.5	500.0	(0.5)	499.5
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	(5.9)	444.1	450.0	(6.2)	443.8
5.45% Senior unsecured notes due 2047	500.0	(0.1)	499.9	500.0	(0.1)	499.9
Debt classified as long-term, including current maturities of long-term debt	$ 4,800.0	$ (5.9)	4,794.1	$ 4,350.0	$ (6.1)	4,343.9
Debt issuance cost (3)			(29.8)			(24.3)
Less: Current maturities of long-term debt (2)			—			(399.8)
Long-term debt, net of unamortized issuance cost			$ 4,764.3			$ 3,919.8

(1) In December 2018, ENLK entered into an $850.0 million, three-year unsecured Term Loan. Borrowings under the Term Loan bear interest based on Prime and/or LIBOR plus an applicable margin. The effective interest rate was 3.9% at December 31, 2018. In connection with the closing of the Merger, the Term Loan was assumed by ENLC, and we became a guarantor of the Term Loan.
(2) The 2.70% senior unsecured notes matured on April 1, 2019. Therefore, the outstanding principal balance, net of discount and debt issuance costs, is classified as "Current maturities of long-term debt" on the consolidated balance sheet as of December 31, 2018.
(3) Net of accumulated amortization of $10.9 million and $15.3 million at December 31, 2019 and 2018, respectively.

Maturities

Maturities for the long-term debt as of December 31, 2019 are as follows (in millions):

2020	$ —
2021	850.0
2022	—
2023	—
2024	900.0
Thereafter	3,050.0
Subtotal	4,800.0
Less: net discount	(5.9)
Less: debt issuance cost	(29.8)
Long-term debt, net of unamortized issuance cost	$ 4,764.3

Related Party Debt

Related party debt includes borrowings under the Consolidated Credit Facility, the Term Loan, and ENLC's 5.375% senior unsecured notes due 2029 to fund the operations and growth capital expenditures of ENLK through a related party arrangement with ENLC. Interest charged to ENLK for borrowings made through the related party arrangement will be substantially the same as interest charged to ENLC on borrowings under the Consolidated Credit Facility, the Term Loan, and ENLC's 5.375%

senior unsecured notes due 2029. As of December 31, 2019, $1,700.0 million of related party debt is included in “Long-term debt” in the consolidated balance sheet related to these borrowings.

The indebtedness under ENLC's 5.375% senior unsecured notes due June 1, 2029, the Consolidated Credit Facility, and the Term Loan was incurred by ENLC but is guaranteed by ENLK. Therefore, the covenants in the agreements governing such indebtedness described below affect balances owed by ENLK on the related party debt.

Consolidated Credit Facility

On December 11, 2018, ENLC entered into the Consolidated Credit Facility, which permits ENLC to borrow up to $1.75 billion on a revolving credit basis and includes a $500.0 million letter of credit subfacility. The Consolidated Credit Facility became available for borrowings and letters of credit upon closing of the Merger. In addition, ENLK became a guarantor under the Consolidated Credit Facility upon the closing of the Merger. In the event that ENLC defaults on the Consolidated Credit Facility, ENLK will be liable for the entire outstanding balance ($350.0 million as of December 31, 2019), and 105% of the outstanding letters of credit under the Consolidated Credit Facility ($4.8 million as of December 31, 2019). The obligations under the Consolidated Credit Facility are unsecured.

The Consolidated Credit Facility includes provisions for additional financial institutions to become lenders, or for any existing lender to increase its revolving commitment thereunder, subject to an aggregate maximum of $2.25 billion for all commitments under the Consolidated Credit Facility.

The Consolidated Credit Facility will mature on January 25, 2024, unless ENLC requests, and the requisite lenders agree, to extend it pursuant to its terms. The Consolidated Credit Facility contains certain financial, operational, and legal covenants. The financial covenants are tested on a quarterly basis, based on the rolling four-quarter period that ends on the last day of each fiscal quarter. The financial covenants include (i) maintaining a ratio of consolidated EBITDA (as defined in the Consolidated Credit Facility, which term includes projected EBITDA from certain capital expansion projects) to consolidated interest charges of no less than 2.5 to 1.0 at all times prior to the occurrence of an investment grade event (as defined in the Consolidated Credit Facility) and (ii) maintaining a ratio of consolidated indebtedness to consolidated EBITDA of no more than 5.0 to 1.0. If ENLC consummates one or more acquisitions in which the aggregate purchase price is $50.0 million or more, ENLC can elect to increase the maximum allowed ratio of consolidated indebtedness to consolidated EBITDA to 5.5 to 1.0 for the quarter in which the acquisition occurs and the three subsequent quarters.

Borrowings under the Consolidated Credit Facility bear interest at ENLC’s option at the Eurodollar Rate (LIBOR) plus an applicable margin (ranging from 1.125% to 2.00%) 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 0.125% to 1.00%). The applicable margins vary depending on ENLC’s debt rating. Upon breach by ENLC of certain covenants governing the Consolidated Credit Facility, amounts outstanding under the Consolidated Credit Facility, if any, may become due and payable immediately.

At December 31, 2019, ENLC was in compliance with and expects to be in compliance with the covenants of the Consolidated Credit Facility for at least the next twelve months. Accordingly, we do not expect to make payments related to our guarantee of the $350.0 million outstanding on the Consolidated Credit Facility.

Term Loan

On December 11, 2018, ENLK entered into the Term Loan with Bank of America, N.A., as Administrative Agent, Bank of Montreal and Royal Bank of Canada, as Co-Syndication Agents, Citibank, N.A. and Wells Fargo Bank, National Association, as Co-Documentation Agents, and the lenders party thereto, and borrowed $850.0 million under the Term Loan.

Upon the closing of the Merger, ENLC assumed ENLK’s obligations under the Term Loan, and ENLK became a guarantor of the Term Loan. In the event that ENLC defaults on the Term Loan and the outstanding balance becomes due, ENLK will be liable for any amount owed on the Term Loan not paid by ENLC. The outstanding balance of the Term Loan was $850.0 million as of December 31, 2019. The obligations under the Term Loan are unsecured.

The Term Loan will mature on December 10, 2021. The Term Loan contains certain financial, operational, and legal covenants. The financial covenants are tested on a quarterly basis, based on the rolling four-quarter period that ends on the last day of each fiscal quarter. The financial covenants include (i) maintaining a ratio of consolidated EBITDA (as defined in the

Term Loan, which term includes projected EBITDA from certain capital expansion projects) to consolidated interest charges of no less than 2.5 to 1.0 at all times prior to the occurrence of an investment grade event (as defined in the Term Loan) and (ii) maintaining a ratio of consolidated indebtedness to consolidated EBITDA of no more than 5.0 to 1.0. If ENLC consummates one or more acquisitions in which the aggregate purchase price is $50.0 million or more, ENLC can elect to increase the maximum allowed ratio of consolidated indebtedness to consolidated EBITDA to 5.5 to 1.0 for the quarter in which the acquisition occurs and the three subsequent quarters.

Borrowings under the Term Loan bear interest at ENLC's option at the Eurodollar Rate (LIBOR) plus an applicable margin (ranging from 1.0% to 1.75%) or the Base Rate (the highest of the Federal Funds Rate plus 0.5%, 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 ENLC's debt rating. Upon breach by ENLC of certain covenants included in the Term Loan, amounts outstanding under the Term Loan may become due and payable immediately.

At December 31, 2019, ENLC was in compliance with and expects to be in compliance with the covenants of the Term Loan for at least the next twelve months. Accordingly, we do not expect to make payments related to our guarantee of the $850.0 million outstanding on the Term Loan.

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. The interest payments on the 2022 Notes were due semi-annually in arrears in June and December. 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 matured 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 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.

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. We received net proceeds of approximately $495.2 million for the issuance of the 2047 notes.

On April 9, 2019, ENLC issued $500.0 million in aggregate principal amount of ENLC’s 5.375% senior unsecured notes due June 1, 2029 at a price to the public of 100% of their face value. Interest payments on the 2029 Notes are payable on June 1 and December 1 of each year. The 2029 Notes are fully and unconditionally guaranteed by ENLK. Net proceeds of approximately $496.5 million were used to repay outstanding borrowings under the Consolidated Credit Facility, including borrowings incurred on April 1, 2019 to repay at maturity all of the $400.0 million outstanding aggregate principal amount of ENLK’s 2.70% senior unsecured notes due 2019, and for general limited liability company purposes.

Senior Unsecured Notes 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
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
2029 Notes	June 1, 2029	Prior to March 1, 2029	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 Notes Indentures

The indentures governing the senior unsecured notes contain covenants that, among other things, limit ENLC’s and ENLK’s ability to create or incur certain liens or consolidate, merge, or transfer all or substantially all of ENLC’s and ENLK’s 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 ENLC and ENLK.

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, 2019, ENLC and ENLK 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 benefit (expense) are as follows (in millions):

	Year Ended December 31,		
	2019	2018	2017
Current income tax expense	$ (0.4)	$ (1.8)	$ (2.6)
Deferred tax benefit (expense)	(2.1)	3.9	26.6
Total income tax benefit (expense)	$ (2.5)	$ 2.1	$ 24.0

Net income for financial statement purposes may differ significantly from taxable income (loss) 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.

The Tax Cuts and Jobs Act of 2017 resulted in a change in the federal statutory corporate tax rate from 35% to 21%, effective January 1, 2018. Accordingly, we recognized a tax benefit of $24.9 million during the fourth quarter of 2017 due to the remeasurement of our deferred tax liabilities to reflect the reduction in the federal statutory corporate tax rate.

Deferred tax liabilities of $44.5 million and $42.4 million existed at December 31, 2019 and 2018, respectively. Deferred tax liabilities as of December 31, 2019 and 2018 included $39.1 million and $38.7 million, respectively, 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.

For the years ended December 31, 2019 and 2018, there was no recorded unrecognized tax benefit. Per our accounting policy election, penalties and interest related to unrecognized tax benefits are recorded to income tax expense. As of December 31, 2019, tax years 2015 through 2019 remain subject to examination by various taxing authorities.

(8) Partners' Capital

(a) Issuance of Common Units

In November 2014, we entered into the 2014 EDA 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 the 2017 EDA.

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

For the year ended December 31, 2018, we sold an aggregate of 2.6 million common units under the 2017 EDA, generating proceeds of $46.1 million (net of $0.5 million of commissions paid to the ENLK Sales Agents). We used the net proceeds for general partnership purposes. In connection with the announcement of the Merger, we suspended solicitation and offers under the 2017 EDA. Following the consummation of the Merger, the 2017 EDA was terminated.

(b) 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 in a private placement for a cash purchase price of $15.00 per Series B Preferred Unit (the "Issue Price"). Affiliates of Goldman Sachs and affiliates of TPG own interests in the general partner of Enfield. Prior to the close of the Merger, the Series B Preferred Units were convertible into our common units on a one-for-one basis, subject to certain adjustments.

Subsequent to the Merger, Series B Preferred Units are exchangeable for ENLC common units in an amount equal to the number of outstanding Series B Preferred Units outstanding multiplied by the exchange ratio of 1.15, subject to certain adjustments (the "Series B Exchange Ratio"). The exchange is subject to ENLK's option to pay cash instead of issuing additional ENLC common units, and can occur in whole or in part at Enfield's option at any time, or in whole at our option, provided the daily volume-weighted average closing price of the ENLC common units (the "ENLC VWAP") exchange for the 30 trading days ending two trading days prior to the exchange is greater than 150% of the Issue Price divided by the conversion ratio of 1.15.

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. Beginning with the quarter ended September 30, 2017, Series B Preferred Unit distributions were payable quarterly in cash at an amount 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 distribution that would have been payable had the Series B Preferred Units converted into our common units over the Cash Distribution Component, divided by (ii) the Issue Price.

Following the closing of the Merger, and beginning with the quarter ended March 31, 2019, the holder of the Series B Preferred Units is entitled to quarterly cash distributions and distributions in-kind of additional Series B Preferred Units as described below. The quarterly in-kind distribution (the "Series B PIK Distribution") equals the greater of (A) 0.0025 Series B Preferred Units per Series B Preferred Unit and (B) the number of Series B Preferred Units equal to the quotient of (x) the excess (if any) of (1) the distribution that would have been payable by ENLC had the Series B Preferred Units been exchanged for ENLC common units but applying a one-to-one exchange ratio (subject to certain adjustments) instead of the Series B Exchange Ratio, over (2) the Cash Distribution Component, divided by (y) the Issue Price. The quarterly cash distribution consists of the Cash Distribution Component plus an amount in cash that will be determined based on a comparison of the value (applying the Issue Price) of (i) the Series B PIK Distribution and (ii) the Series B Preferred Units that would have been distributed in the Series B PIK Distribution if such calculation applied the Series B Exchange Ratio instead of the one-to-one ratio (subject to certain adjustments).

Income is allocated to the Series B Preferred Units in an amount equal to the quarterly distribution with respect to the period earned. A summary of the distribution activity relating to the Series B Preferred Units for the years ended December 31, 2019, 2018, and 2017 is provided below:

Declaration period	Distribution paid as additional Series B Preferred Units	Cash distribution (in millions)	Date paid/payable
2019			
First Quarter of 2019	147,887	$ 16.7	May 14, 2019
Second Quarter of 2019	148,257	$ 17.1	August 13, 2019
Third Quarter of 2019	148,627	$ 17.1	November 13, 2019
Fourth Quarter of 2019	148,999	$ 16.8	February 13, 2020
2018			
First Quarter of 2018	416,657	$ 16.2	May 14, 2018
Second Quarter of 2018	419,678	$ 16.3	August 13, 2018
Third Quarter of 2018	422,720	$ 16.4	November 13, 2018
Fourth Quarter of 2018	425,785	$ 16.5	February 13, 2019
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

(d) Series C Preferred Units

In September 2017, we issued 400,000 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 the ENLK 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%. Income is allocated to the Series C Preferred Units in an amount equal to the earned distribution for the respective reporting period.

Following the Merger, the Series C Preferred Units remain issued and outstanding with the terms set forth above.

(e) Common Unit Distributions

Prior to the Merger, unless restricted by the terms of the ENLK Credit Facility and/or the indentures governing our senior unsecured notes, we were required to make distributions of 100% of available cash, as defined in the partnership agreement, within 45 days following the end of each quarter. Distributions were made to the general partner in accordance with its then 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 were 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 was 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.

Prior to the Merger, our general partner owned the general partner interest in us and all of our incentive distribution rights. Our general partner was entitled to receive incentive distributions if the amount we distributed with respect to any quarter exceeded levels specified in its partnership agreement. Under the quarterly incentive distribution provisions, our general partner was entitled to 13.0% of amounts we distributed in excess of $0.25 per unit, 23.0% of the amounts we distributed in excess of $0.3125 per unit, and 48.0% of amounts we distributed in excess of $0.375 per unit. At the closing of the Merger, our general partner's incentive distribution rights in ENLK were eliminated. See "Note 1—Organization and Summary of Significant Agreements" for more information regarding the Merger and related transactions.

A summary of ENLK's distribution activity relating to the common units for periods prior to the Merger is provided below:

Declaration period		Distribution/unit	Date paid/payable
2018			
First Quarter of 2018	$	0.390	May 14, 2018
Second Quarter of 2018	$	0.390	August 13, 2018
Third Quarter of 2018	$	0.390	November 13, 2018
Fourth Quarter of 2018	$	0.390	February 13, 2019
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

Following the Merger, we distributed $527.6 million to ENLC related to its ownership of our common units for the year ended December 31, 2019.

(f) Allocation of ENLK Income

Prior to the closing of the Merger and for the years ended December 31, 2018 and 2017, net income was 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 was not entitled to incentive distributions with respect to (i) distributions on the Series B Preferred Units until such units converted into common units or (ii) the Series C Preferred Units. At the closing of the Merger, our general partner's incentive distribution rights were eliminated.

For the years ended December 31, 2018 and 2017, our general partner's share of net income consisted 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 ENLK's net income adjusted for ENLC's unit-based compensation specifically allocated to our general partner. For the years ended December 31, 2019, 2018, and 2017, the net income allocated to the general partner is as follows (in millions):

	Year Ended December 31,		
	2019	2018	2017
Income allocation for incentive distributions	$ —	$ 59.5	$ 58.9
Unit-based compensation attributable to ENLC's restricted and performance units	(37.0)	(20.3)	(21.0)
General partner share of net income (loss)	(1.4)	(0.6)	0.4
General partner interest in EOGP acquisition	2.4	27.5	4.8
General partner interest in net income (loss)	$ (36.0)	$ 66.1	$ 43.1

(9) Investment in Unconsolidated Affiliates

As of December 31, 2019, our unconsolidated investments consisted ofa 38.75% ownership interest in GCF and a 30.0% ownership in the Cedar Cove JV. The following table shows the activity related to our investment in unconsolidated affiliates for the periods indicated (in millions):

	Year Ended December 31,		
	2019	2018	2017
GCF			
Distributions	$ 19.2	$ 22.3	$ 12.7
Equity in income	$ 16.5	$ 15.8	$ 12.6
HEP			
Equity in loss (1)	$ —	$ —	$ (3.4)
Cedar Cove JV			
Contributions	$ —	$ 0.1	$ 12.6
Distributions	$ 1.0	$ 0.4	$ 0.8
Equity in income (loss) (2)	$ (33.3)	$ (2.5)	$ 0.4
Total			
Contributions	$ —	$ 0.1	$ 12.6
Distributions	$ 20.2	$ 22.7	$ 13.5
Equity in income (loss) (1)(2)	$ (16.8)	$ 13.3	$ 9.6

(1) Includes a loss of $3.4 million for the year ended December 31, 2017 related to the sale of our HEP interests . In March 2017, we sold an approximate 31.0% ownership interest in HEP for aggregate net proceeds of $189.7 million.
(2) Includes a loss of $31.4 million for the year ended December 31, 2019 related to the impairment of the carrying value of the Cedar Cove JV, as we determined that the carrying value of our investment was not recoverable based on the forecasted cash flows from the Cedar Cove JV.

The following table shows the balances related to our investment in unconsolidated affiliates as ofDecember 31, 2019 and 2018 (in millions):

	December 31, 2019	December 31, 2018
GCF	$ 39.2	$ 41.9
Cedar Cove JV	3.9	38.2
Total investment in unconsolidated affiliates	$ 43.1	$ 80.1

(10) Employee Incentive Plans

(a) Long-Term Incentive Plans

Prior to the Merger, ENLC and ENLK each had similar unit-based compensation payment plans for officers and employees. ENLC grants unit-based awards under the 2014 Plan, and ENLK granted unit-based awards under the GP Plan. As of the closing of the Merger, (i) ENLC assumed all obligations in respect of the GP Plan and the outstanding awards granted thereunder (the “Legacy ENLK Awards”) and (ii) the Legacy ENLK Awards converted into ENLC unit-based awards using the 1.15 exchange ratio (as defined in the Merger Agreement) as the conversion rate. In addition, as of the closing of the Merger, the performance metric of each Legacy ENLK Award and each then outstanding award under the 2014 Plan with performance-based vesting conditions was modified as discussed in (c) and (e) below. Following the consummation of the Merger, no additional awards will be granted under the GP 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 plans awarded to ENLC's directors, officers, and employees is recorded by us since ENLC has no substantial or managed operating activities other than its interests in us.

Amounts recognized on the consolidated financial statements with respect to these plans are as follows (in millions):

	Year Ended December 31,		
	2019	2018	2017
Cost of unit-based compensation charged to general and administrative expense	$ 32.5	$ 30.0	$ 37.1
Cost of unit-based compensation charged to operating expense	6.7	10.8	10.7
Total unit-based compensation expense	$ 39.2	$ 40.8	$ 47.8

All unit-based awards issued and outstanding immediately prior to the effective time of the Merger under the GP Plan have been converted into an award with respect to ENLC common units with substantially similar terms as were in effect immediately prior to the effective time, with certain adjustments to the performance-based vesting of terms of applicable awards related to the performance of ENLC.

(b) EnLink Midstream Partners, LP Restricted Incentive Units

ENLK restricted incentive units were valued at their fair value at the date of grant, which is equal to the market value of ENLK common units on such dateA summary of the restricted incentive unit activity for the year ended December 31, 2019 is provided below:

	Year Ended December 31, 2019	
EnLink Midstream Partners, LP Restricted Incentive Units:	**Number of Units**	**Weighted Average Grant-Date Fair Value**
Non-vested, beginning of period	2,556,270	$ 14.43
Vested (1)	(722,853)	10.02
Forfeited	(4,490)	11.93
Converted to ENLC (2)	(1,828,927)	16.11
Non-vested, end of period	—	$ —

(1) Vested units included 249,201 units withheld for payroll taxes paid on behalf of employees.
(2) As a result of the Merger, the Legacy ENLK Awards converted into ENLC unit-based awards using the 1.15 exchange ratio (as defined in the Merger Agreement) as the conversion rate.

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) for the years ended December 31, 2019, 2018, and 2017 is provided below (in millions). Since the Legacy ENLK Awards converted into ENLC unit-based awards as a result of the Merger, no additional restricted incentive units will vest as ENLK units under the GP Plan (such restricted incentive units, as converted, are eligible to vest as ENLC units) and no additional expense will be recognized after January 25, 2019 under the GP Plan.

	Year Ended December 31,		
EnLink Midstream Partners, LP Restricted Incentive Units:	**2019**	**2018**	**2017**
Aggregate intrinsic value of units vested	$ 8.0	$ 13.1	$ 16.6
Fair value of units vested	$ 7.2	$ 16.4	$ 22.6

(c) EnLink Midstream Partners, LP Performance Units

Prior to the Merger, our general partner granted performance awards under the GP Plan. The performance award agreements provided that the vesting of performance units (i.e., performance-based restricted incentive units) granted thereunder was 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 contemplated that the Peer Companies for an individual performance award (the "Subject Award") were the companies comprising the AMZ, excluding ENLK and ENLC, on the grant date for the Subject Award. The performance units would 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. As of the closing of the Merger, these performance-based Legacy ENLK Awards were modified, such that, the performance goal will, on a weighted average basis, (i) continue to relate to the EnLink TSR relative to the TSR performance of the Peer Companies in respect of periods preceding the effective time of the Merger; and (ii) relate solely to the TSR performance of ENLC relative to the TSR performance of such Peer Companies in respect of periods on and after the effective time of the Merger. 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 performance units ranges from zero to 200% of the performance units granted depending on the extent to which the related performance goals are achieved over the relevant performance period.

The fair value of each performance unit was 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 ENLK's common units and the designated Peer Companies' securities; (iii) an estimated ranking of ENLK and ENLC among the designated 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.

EnLink Midstream Partners, LP Performance Units:	March 2018	March 2017
Grant-date fair value	$ 19.24	$ 25.73
Beginning TSR price	$ 15.44	$ 17.55
Risk-free interest rate	2.38%	1.62%
Volatility factor	43.85%	43.94%
Distribution yield	10.5%	8.7%

The following table presents a summary of the performance units:

	Year Ended December 31, 2019	
EnLink Midstream Partners, LP Performance Units:	Number of Units	Weighted Average Grant-Date Fair Value
Non-vested, beginning of period	451,669	$ 17.74
Vested (1)	(161,410)	10.54
Converted to ENLC (2)	(290,259)	28.31
Non-vested, end of period	—	$ —

(1) Vested units included 62,403 units withheld for payroll taxes paid on behalf of employees.
(2) As a result of the Merger, the performance-based Legacy ENLK Awards converted into ENLC unit-based performance awards using the 1.15 exchange ratio (as defined in the Merger Agreement) as the conversion rate.

A summary of the performance units' aggregate intrinsic value (market value at vesting date) and fair value of units vested (market value at date of grant) for the years ended December 31, 2019 and 2018 is provided below (in millions). Since the Legacy ENLK Awards converted into ENLC unit-based awards as a result of the Merger, no additional performance units will vest as ENLK units under the GP Plan (such performance units, as converted, are eligible to vest as ENLC units) and no additional expense will be recognized after January 25, 2019 under the GP Plan. No performance units vested for the year ended December 31, 2017.

	Year Ended December 31,	
EnLink Midstream Partners, LP Performance Units:	**2019**	**2018**
Aggregate intrinsic value of units vested	$ 2.1	$ 5.0
Fair value of units vested	$ 1.7	$ 7.7

(d) EnLink Midstream, LLC 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 ENLC common units on such dateA summary of the restricted incentive unit activity for the year ended December 31, 2019 is provided below:

	Year Ended December 31, 2019	
EnLink Midstream, LLC Restricted Incentive Units:	**Number of Units**	**Weighted Average Grant-Date Fair Value**
Non-vested, beginning of period	2,425,867	$ 14.62
Granted (1)	2,027,653	11.09
Vested (1)(2)	(1,886,905)	12.06
Forfeited	(606,276)	13.85
Converted from ENLK (3)	2,103,266	14.01
Non-vested, end of period	4,063,605	$ 13.85
Aggregate intrinsic value, end of period (in millions)	$ 24.9	

(1) Restricted incentive units typically vest at the end of three years. In March 2019, ENLC granted 420,842 restricted incentive units with a fair value of $4.8 million to officers and certain employees as bonus payments for 2018, and these restricted incentive units vested immediately and are included in the restricted incentive units granted and vested line items.
(2) Vested units included 626,133 units withheld for payroll taxes paid on behalf of employees.
(3) Represents Legacy ENLK Awards that were converted into ENLC unit-based awards using the 1.15 exchange ratio (as defined in the Merger Agreement) as the conversion rate.

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) for the years ended December 31, 2019, 2018, and 2017 is provided below (in millions):

	Year Ended December 31,		
EnLink Midstream, LLC Restricted Incentive Units:	**2019**	**2018**	**2017**
Aggregate intrinsic value of units vested	$ 17.3	$ 12.8	$ 15.3
Fair value of units vested	$ 22.8	$ 16.5	$ 22.2

As of December 31, 2019, there were $23.1 million of unrecognized compensation costs related to non-vested ENLC restricted incentive units. This cost is expected to be recognized over a weighted average period of 1.6 years.

For restricted incentive unit awards granted after March 8, 2019 to certain officers and employees (the "grantee"), such awards (the "Subject Grants") generally provide that, subject to the satisfaction of the conditions set forth in the agreement, the Subject Grants will vest on the third anniversary of the vesting commencement date (the "Regular Vesting Date"). The Subject Grants will be forfeited if the grantee's employment or service with ENLC and its affiliates terminates prior to the Regular Vesting Date except that the Subject Grants will vest in full or on a pro-rated basis for certain terminations of employment or service prior to the Regular Vesting Date. For instance, the Subject Grants will vest on a pro-rated basis for any terminations of the grantee's employment: (i) due to retirement, (ii) by ENLC or its affiliates without cause, or (iii) by the grantee for good reason (each, a "Covered Termination" and more particularly defined in the Subject Grants agreement) except that the Subject Grants will vest in full if the applicable Covered Termination is a "normal retirement" (as defined in the Subject Grants agreement) or the applicable Covered Termination occurs after a change of control (if any). The Subject Grants will vest in full if death or a qualifying disability occurs prior to the Regular Vesting Date.

(e) EnLink Midstream, LLC Performance Units

ENLC grants performance awards under the 2014 Plan. The performance award agreements provide that the vesting of performance units (i.e., performance-based restricted incentive units) granted thereunder is dependent on the achievement of certain performance goals over the applicable performance period. 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 extent to which the related performance goals are achieved over the relevant performance period.

Performance awards granted prior to March 8, 2019 provided that the vesting of performance units granted was dependent on the achievement of certain TSR performance goals relative to the TSR achievement of the Peer Companies over the applicable performance period. Prior to the Merger, vesting of the performance units was based on the percentile ranking of the EnLink TSR for the applicable performance period relative to the TSR achievement of the Peer Companies. As of the effective time of the Merger, these performance-based awards were modified, such that, the performance goal will, on a weighted average basis, (i) continue to relate to the EnLink TSR relative to the TSR performance of the Peer Companies in respect of periods preceding the effective time of the Merger; and (ii) relate solely to the TSR performance of ENLC relative to the TSR performance of such Peer Companies in respect of periods on and after the effective time of the Merger.

2019 Performance Unit Awards

For performance awards granted after March 8, 2019 to the grantee, the vesting of performance units is dependent on (a) the grantee's continued employment or service with ENLC or its affiliates for all relevant periods and (b) the TSR performance of ENLC (the "ENLC TSR") and a performance goal based on cash flow ("Cash Flow"). At the time of grant, the Board of Directors of the managing member of ENLC (the "Manager Board") will determine the relative weighting of the two performance goals by including in the award agreement the number of units that will be eligible for vesting depending on the achievement of the TSR performance goals (the "Total TSR Units") versus the achievement of the Cash Flow performance goals (the "Total CF Units"). These performance awards have four separate performance periods: (i) three performance periods are each of the first, second, and third calendar years that occur following the vesting commencement date of the performance awards and (ii) the fourth performance period is the cumulative three-year period from the vesting commencement date through the third anniversary thereof (the "Cumulative Performance Period").

One-fourth of the Total TSR Units (the "Tranche TSR Units") relates to each of the four performance periods described above. Following the end date of a given performance period, the Governance and Compensation Committee (the "Manager Committee") of the Manager Board will measure and determine the ENLC TSR relative to the TSR performance of a designated group of peer companies (the "Designated Peer Companies") to determine the Tranche TSR Units that are eligible to vest, subject to the grantee's continued employment or service with ENLC or its affiliates through the end date of the Cumulative Performance Period. In short, the TSR for a given performance period is defined as (i)(A) the average closing price of a common equity security at the end of the relevant performance period minus (B) the average closing price of a common equity security at the beginning of the relevant performance period plus (C) reinvested dividends divided by (ii) the average closing price of a common equity security at the beginning of the relevant performance period.

The following table sets out the levels at which the Tranche TSR Units may vest (using linear interpolation) based on the ENLC TSR percentile ranking for the applicable performance period relative to the TSR achievement of the Designated Peer Companies:

Performance Level	Achieved ENLC TSR Position Relative to Designated Peer Companies	Vesting percentage of the Tranche TSR Units
Below Threshold	Less than 25%	0%
Threshold	Equal to 25%	50%
Target	Equal to 50%	100%
Maximum	Greater than or Equal to 75%	200%

Approximately one-third of the Total CF Units (the "Tranche CF Units") relates to each of the first three performance periods described above (i.e., the Cash Flow performance goal does not relate to the Cumulative Performance Period). The Manager Board will establish the Cash Flow performance targets for purposes of the column in the table below titled "ENLC's Achieved Cash Flow" for each performance period no later than March 31 of the year in which the relevant performance period begins. Following the end date of a given performance period, the Manager Committee will measure and determine the Cash Flow performance of ENLC to determine the Tranche CF Units that are eligible to vest, subject to the grantee's continued employment or service with ENLC or its affiliates through the end of the Cumulative Performance Period. In short, the Performance-Based Award Agreement defines Cash Flow for a given performance period as (A)(i) ENLC's adjusted EBITDA minus (ii) interest expense, current taxes and other, maintenance capital expenditures, and preferred unit accrued distributions divided by (B) the time-weighted average number of ENLC's common units outstanding during the relevant performance period. The following table sets out the levels at which the Tranche CF Units will be eligible to vest (using linear interpolation) based on the Cash Flow performance of ENLC for the performance period ending December 31, 2019:

Performance Level	ENLC's Achieved Cash Flow	Vesting percentage of the Tranche CF Units
Below Threshold	Less than $1.43	0%
Threshold	Equal to $1.43	50%
Target	Equal to $1.55	100%
Maximum	Greater than or Equal to $1.72	200%

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' or Peer Companies' securities as applicable; (iii) an estimated ranking of ENLC (or for outstanding performance units granted prior to the Merger, ENLC and ENLK) among the Designated Peer Companies or 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 value assumptions by performance unit grant date:

EnLink Midstream, LLC Performance Units:	October 2019	June 2019	March 2019	March 2018	March 2017
Grant-date fair value	$ 7.29	$ 9.92	$ 13.10	$ 21.63	$ 28.77
Beginning TSR price	$ 7.42	$ 9.84	$ 10.92	$ 16.55	$ 18.29
Risk-free interest rate	1.44%	1.72%	2.42%	2.38%	1.62%
Volatility factor	35.00%	33.50%	33.86%	51.36%	52.07%
Distribution yield	10.1%	11.5%	9.7%	6.7%	5.4%

The following table presents a summary of the performance units:

	Year Ended December 31, 2019	
EnLink Midstream, LLC Performance Units:	**Number of Units**	**Weighted Average Grant-Date Fair Value**
Non-vested, beginning of period	418,149	$ 19.15
Granted	1,202,105	11.73
Vested (1)	(374,745)	21.08
Forfeited	(261,451)	15.68
Converted from ENLK (2)	333,798	25.84
Non-vested, end of period	1,317,856	$ 14.22
Aggregate intrinsic value, end of period (in millions)	$ 8.1	

(1) Vested units included 146,218 units withheld for payroll taxes paid on behalf of employees.
(2) As a result of the Merger, the performance-based Legacy ENLK Awards converted into ENLC performance-based awards using the 1.15 exchange ratio (as defined in the Merger Agreement) as the conversion rate.

A summary of the performance units' aggregate intrinsic value (market value at vesting date) and fair value of units vested (market value at date of grant) for the years ended December 31, 2019 and 2018 is provided below (in millions). No performance units vested for the year ended December 31, 2017.

	Year Ended December 31,	
EnLink Midstream, LLC Performance Units:	**2019**	**2018**
Aggregate intrinsic value of units vested	$ 3.4	$ 4.7
Fair value of units vested	$ 7.9	$ 7.7

As of December 31, 2019, there were $10.2 million of unrecognized compensation costs that related to non-vested performance units. These costs are expected to be recognized over a weighted-average period of 1.8 years.

In connection with the GIP Transaction, certain outstanding performance unit agreements were modified to, among other things: (i) provide that the awards granted thereunder did not vest due to the closing of the GIP Transaction, and (ii) increase the minimum vesting of units from zero to 100% as described in our Current Report on Form 8-K filed with the Commission on July 23, 2018. The modified performance units retained the original vesting schedules. As a result of the modifications, we will recognize an additional $2.1 million compensation cost over the life of these ENLC performance units.

In connection with the Merger, Legacy ENLK Awards with "performance-based" vesting and payment conditions were modified to reflect the Performance Metric Adjustment (as defined in the Merger Agreement) as described in our Current Report on Form 8-K filed with the Commission on January 29, 2019. The modified performance units retained the original vesting schedules. As a result of the modifications, we will recognize an additional $0.7 million in compensation costs over the life of the Legacy ENLK Awards.

(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 eligible compensation plus a 2% non-discretionary contribution (not to exceed the maximum amount permitted by law). Contributions of $9.4 million, $8.3 million, and $7.6 million were made to the plan for the years ended December 31, 2019, 2018, and 2017, respectively.

(11) Derivatives

Interest Rate Swaps

We periodically enter into interest rate swaps during the debt issuance process to hedge 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 or to hedge variability in cash flows on our variable-rate debt. We designate interest rate swaps as cash flow hedges in accordance with ASC 815.

In April 2019, we entered into an $850.0 million interest rate swap with ENLC, which mirrored the terms of ENLC's interest rate swap with a third party,to manage the interest rate risk associated with our floating-rate, LIBOR-based borrowings. Under this arrangement, we pay a fixed interest rate of 2.27825% in exchange for LIBOR-based variable interest through December 2021. Assets or liabilities related to this interest rate swap contract are included in the fair value of derivative assets and liabilities on the consolidated balance sheets, and the change in fair value of this contract is recorded net as gain or loss on designated cash flow hedges on the consolidated statements of comprehensive income. Monthly, upon settlement, we reclassify the gain or loss associated with the interest rate swap into interest expense from accumulated other comprehensive income (loss). There is no ineffectiveness related to this hedge.

In May 2017, we entered into an interest rate swap in connection with the issuance of our 2047 Notes. Upon settlement of the interest rate swap in May 2017, we recorded the associated $2.2 million settlement loss in accumulated comprehensive loss on the consolidated balance sheets. We 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. In addition, the settlement loss was 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, 2019, we recorded $12.4 million into accumulated other comprehensive loss related to changes in fair value of our interest rate swaps.

For the year ended December 31, 2019, we realized a loss of $0.4 million related to the monthly settlement of our interest rate swaps and an immaterial amount of amortization, which we recorded into interest expense, net of interest income from accumulated other comprehensive loss. For the years ended December 31, 2018 and 2017, we amortized an immaterial amount of the settlement loss into interest expense, net of interest income from accumulated other comprehensive loss. We expect to recognize an additional $5.7 million of interest expense out of accumulated other comprehensive loss over the next twelve months.

The fair value of our interest rate swaps included in our consolidated balance sheets were as follows (in millions):

	December 31, 2019
Fair value of derivative liabilities—current	$ (5.6)
Fair value of derivative liabilities—long-term	(6.8)
Net fair value of derivatives	$ (12.4)

Commodity Swaps

We manage our exposure to changes in commodity prices by hedging the impact of market fluctuations. Commodity swaps are used both to manage and hedge price and location risk related to these market exposures and 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 swaps 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 commodity 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. For condensate, crude oil, and natural gas, index swaps 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 oil, 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.

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.

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,		
	2019	2018	2017
Change in fair value of derivatives	$ (0.1)	$ 10.1	$ 4.7
Realized gain (loss) on derivatives	14.5	(4.9)	(8.9)
Gain (loss) on derivative activity	$ 14.4	$ 5.2	$ (4.2)

The fair value of derivative assets and liabilities related to commodity swaps are as follows (in millions):

	December 31, 2019	December 31, 2018
Fair value of derivative assets—current	$ 12.9	$ 28.6
Fair value of derivative assets—long-term	4.3	4.1
Fair value of derivative liabilities—current	(8.8)	(21.8)
Fair value of derivative liabilities—long-term	—	(2.4)
Net fair value of derivatives	$ 8.4	$ 8.5

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, 2019 (in millions). The remaining term of the contracts extend no later thanDecember 2022.

		December 31, 2019		
Commodity	Instruments	Unit	Volume	Net Fair Value
NGL (short contracts)	Swaps	Gallons	(64.0)	$ 1.7
NGL (long contracts)	Swaps	Gallons	11.7	(0.5)
Natural gas (short contracts)	Swaps	MMBtu	(4.7)	1.0
Natural gas (long contracts)	Swaps	MMBtu	3.7	(0.4)
Crude and condensate (short contracts)	Swaps	MMbbls	(12.8)	(1.0)
Crude and condensate (long contracts)	Swaps	MMbbls	2.0	7.6
Total fair value of derivatives				$ 8.4

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 financial institutions when entering into financial derivatives on commodities. We have entered into Master 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, the maximum loss on our gross receivable position of $17.2 million as of December 31, 2019 would be reduced to$8.4 million due to the offsetting of gross fair value payables against gross fair value receivables as allowed by the ISDAs.

(12) 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.

Assets and liabilities measured at fair value on a recurring basis are summarized below (in millions):

	Level 2	
	December 31, 2019	December 31, 2018
Interest rate swaps (1)	$ (12.4)	$ —
Commodity swaps (2)	$ 8.4	$ 8.5

(1) The fair values of the interest rate swaps are estimated based on the difference between expected cash flows calculated at the contracted interest rates and the expected cash flows using observable benchmarks for the variable interest rates.
(2) The fair values of commodity swaps represent the amount at which the instruments could be exchanged in a current arms-length transaction adjusted for our credit risk and/or the counterparty credit risk 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, 2019		December 31, 2018	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Long-term debt (1)	$ 4,764.3	$ 4,444.2	$ 4,319.6	$ 3,953.6
Obligations under financing lease	$ —	$ —	$ 2.5	$ 2.2
Secured term loan receivable (2)	$ —	$ —	$ 51.1	$ 51.1

(1) The carrying value of long-term debt as of December 31, 2018 includes current maturities. The carrying value of the long-term debt is reduced by debt issuance costs of $29.8 million and $24.3 million at December 31, 2019 and 2018, respectively. The respective fair values do not factor in debt issuance costs.
(2) In late May 2019, White Star, the counterparty to our $58.0 million second lien secured term loan receivable, filed for reorganization under Chapter 11 of the U.S. Bankruptcy Code and was not able to repay the outstanding amounts owed to us under the second lien secured term loan. For additional information regarding this transaction, refer to "Note 2—Significant Accounting Policies."

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.

As of December 31, 2019, ENLC had total borrowings under senior unsecured notes of $500.0 million maturing in 2029 with a fixed interest rate of 5.375%. As of December 31, 2019, we had total borrowings under senior unsecured notes of $3.1 billion maturing between 2024 and 2047 with fixed interest rates ranging from 4.15% to 5.60%. As of December 31, 2018, we had total borrowings under senior unsecured notes of $3.5 billion maturing between 2019 and 2047 with fixed interest rates ranging from 2.70% to 5.60%.

The fair values of all senior unsecured notes as of December 31, 2019 and 2018 were based on Level 2 inputs from third-party market quotations. The fair values of the secured term loan receivable were calculated using Level 2 inputs from third-party banks.

(13) Commitments and Contingencies

(a) 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.

(b) 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.

(c) 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 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 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.

(14) Segment Information

Effective January 1, 2019, we changed our reportable operating segments to reflect how we currently make financial decisions and allocate resources. Prior to January 1, 2019, our reportable operating segments consisted of the following: (i) natural gas gathering, processing, transmission, and fractionation operations located in North Texas and the Permian Basin primarily in West Texas, (ii) natural gas pipelines, processing plants, storage facilities, NGL pipelines, and fractionation assets in Louisiana, (iii) natural gas gathering and processing operations located throughout Oklahoma, and (iv) crude rail, truck, pipeline, and barge facilities in West Texas, South Texas, Louisiana, Oklahoma, and ORV. Effective January 1, 2019, we are reporting financial performance in five segments: Permian, North Texas, Oklahoma, Louisiana, and Corporate. Crude and condensate operations are combined regionally with natural gas and NGL operations in the Oklahoma and Permian segments, and ORV operations are included in the Louisiana segment. We have recast the segment information for the years ended December 31, 2018 and 2017 to conform to the current period presentation.

Identification of the majority of our operating segments is based principally upon geographic regions served:

- *Permian Segment.* The Permian segment includes our natural gas gathering, processing, and transmission activities and our crude oil operations in the Midland and Delaware Basins in West Texas and Eastern New Mexico and our crude operations in South Texas;

- *North Texas Segment.* The North Texas segment includes our natural gas gathering, processing, and transmission activities in North Texas;

- *Oklahoma Segment.* The Oklahoma segment includes our natural gas gathering, processing, and transmission activities, and our crude oil operations in the Cana-Woodford, Arkoma-Woodford, northern Oklahoma Woodford, STACK, and CNOW shale 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 and our crude oil operations in ORV; and

- *Corporate Segment.* The Corporate segment includes our unconsolidated affiliate investments in the Cedar Cove JV in Oklahoma, our ownership interest in GCF in South Texas, our derivative activity, and our general corporate assets and expenses.

Based on the disclosure requirements of ASC 606, we are presenting revenues disaggregated based on the type of good or service in order to more fully depict the nature of our revenues. As we adopted ASC 606 using the modified retrospective method, only the consolidated statement of operations and revenue disaggregation information for the years ended December 31, 2019 and 2018 are presented to conform to ASC 606 accounting and disclosure requirements. Prior periods presented in the consolidated financial statements and accompanying notes were not restated in accordance with ASC 606.

We evaluate the performance of our operating segments based on segment profits.Summarized financial information for our reportable segments is shown in the following tables (in millions):

	Permian	North Texas	Oklahoma	Louisiana	Corporate	Totals
Year Ended December 31, 2019						
Natural gas sales	$ 94.3	$ 129.3	$ 236.4	$ 416.6	$ —	$ 876.6
NGL sales	0.9	30.9	19.6	1,725.6	—	1,777.0
Crude oil and condensate sales	1,975.0	—	109.6	291.9	—	2,376.5
Product sales	2,070.2	160.2	365.6	2,434.1	—	5,030.1
Natural gas sales—related parties	0.4	—	—	—	(0.4)	—
NGL sales—related parties	347.7	94.8	421.1	25.7	(889.3)	—
Crude oil and condensate sales—related parties	13.5	5.5	—	1.7	(20.7)	—
Product sales—related parties	361.6	100.3	421.1	27.4	(910.4)	—
Gathering and transportation	48.8	196.4	234.5	58.3	—	538.0
Processing	30.5	143.0	138.2	3.2	—	314.9
NGL services	—	0.1	—	50.6	—	50.7
Crude services	19.2	—	19.8	51.9	—	90.9
Other services	12.0	1.1	0.1	0.7	—	13.9
Midstream services	110.5	340.6	392.6	164.7	—	1,008.4
NGL services—related parties	—	—	—	(3.4)	3.4	—
Crude services—related parties	—	—	1.8	—	(1.8)	—
Midstream services—related parties	—	—	1.8	(3.4)	1.6	—
Revenue from contracts with customers	2,542.3	601.1	1,181.1	2,622.8	(908.8)	6,038.5
Cost of sales	(2,283.9)	(208.8)	(627.0)	(2,181.6)	908.8	(4,392.5)
Operating expenses	(112.9)	(102.9)	(104.0)	(147.3)	—	(467.1)
Gain on derivative activity	—	—	—	—	14.4	14.4
Segment profit	$ 145.5	$ 289.4	$ 450.1	$ 293.9	$ 14.4	$ 1,193.3
Depreciation and amortization	$ (119.8)	$ (139.8)	$ (194.9)	$ (154.1)	$ (8.4)	$ (617.0)
Impairments	$ (3.5)	$ (2.1)	$ (190.5)	$ (2.1)	$ —	$ (198.2)
Capital expenditures	$ 364.5	$ 39.0	$ 238.1	$ 99.9	$ 6.9	$ 748.4

	Permian	North Texas	Oklahoma	Louisiana	Corporate	Totals
Year Ended December 31, 2018						
Natural gas sales	$ 152.3	$ 140.6	$ 189.7	$ 531.1	$ —	$ 1,013.7
NGL sales	0.5	29.0	25.2	2,786.3	—	2,841.0
Crude oil and condensate sales	2,344.1	0.5	85.9	227.1	—	2,657.6
Product sales	2,496.9	170.1	300.8	3,544.5	—	6,512.3
Natural gas sales—related parties	(0.3)	—	2.5	0.3	—	2.5
NGL sales—related parties	454.1	49.4	590.8	47.4	(1,104.3)	37.4
Crude oil and condensate sales—related parties	—	1.8	0.3	0.2	(1.2)	1.1
Product sales—related parties	453.8	51.2	593.6	47.9	(1,105.5)	41.0
Gathering and transportation	28.0	146.3	143.2	68.8	—	386.3
Processing	23.8	83.9	128.7	3.3	—	239.7
NGL services	—	—	—	59.6	—	59.6
Crude services	4.2	—	2.8	60.1	—	67.1
Other services	8.7	0.9	0.1	0.9	—	10.6
Midstream services	64.7	231.1	274.8	192.7	—	763.3
Gathering and transportation—related parties	—	122.7	80.6	—	—	203.3
Processing—related parties	—	108.5	48.5	—	—	157.0
NGL services—related parties	—	—	—	3.3	(3.3)	—
Crude services—related parties	14.9	—	1.5	—	—	16.4
Other services—related parties	—	0.5	—	—	—	0.5
Midstream services—related parties	14.9	231.7	130.6	3.3	(3.3)	377.2
Revenue from contracts with customers	3,030.3	684.1	1,299.8	3,788.4	(1,108.8)	7,693.8
Cost of sales	(2,808.3)	(199.2)	(743.6)	(3,365.7)	1,108.8	(6,008.0)
Operating expenses	(96.1)	(112.7)	(90.3)	(154.3)	—	(453.4)
Gain on derivative activity	—	—	—	—	5.2	5.2
Segment profit	$ 125.9	$ 372.2	$ 465.9	$ 268.4	$ 5.2	$ 1,237.6
Depreciation and amortization	$ (111.0)	$ (127.9)	$ (178.8)	$ (150.9)	$ (8.7)	$ (577.3)
Impairments	$ (138.5)	$ (202.7)	$ —	$ (24.6)	$ —	$ (365.8)
Goodwill	$ —	$ —	$ 190.3	$ —	$ —	$ 190.3
Capital expenditures	$ 271.7	$ 24.7	$ 493.8	$ 54.4	$ 5.3	$ 849.9

	Permian	North Texas	Oklahoma	Louisiana	Corporate	Totals
Year Ended December 31, 2017						
Product sales	$ 1,344.0	$ 162.5	$ 128.8	$ 2,723.1	$ —	$ 4,358.4
Product sales—related parties	357.0	120.5	349.4	39.8	(721.8)	144.9
Midstream services	77.5	51.6	155.0	268.2	—	552.3
Midstream services—related parties	18.7	410.4	241.6	151.1	(133.6)	688.2
Cost of sales	(1,628.5)	(264.5)	(523.0)	(2,800.9)	855.4	(4,361.5)
Operating expenses	(85.1)	(121.8)	(64.6)	(147.2)	—	(418.7)
Loss on derivative activity	—	—	—	—	(4.2)	(4.2)
Segment profit (loss)	$ 83.6	$ 358.7	$ 287.2	$ 234.1	$ (4.2)	$ 959.4
Depreciation and amortization	$ (109.9)	$ (127.0)	$ (156.3)	$ (141.7)	$ (10.4)	$ (545.3)
Impairments	$ —	$ —	$ —	$ (17.1)	$ —	$ (17.1)
Goodwill	$ 29.3	$ 202.7	$ 190.3	$ —	$ —	$ 422.3
Capital expenditures	$ 186.1	$ 18.2	$ 450.1	$ 87.3	$ 26.4	$ 768.1

The following table reconciles the segment profits reported above to theoperating income as reported on the consolidated statements of operations (in millions):

	Year Ended December 31,		
	2019	2018	2017
Segment profit	$ 1,193.3	$ 1,237.6	$ 959.4
General and administrative expenses	(139.2)	(130.2)	(123.5)
Gain (loss) on disposition of assets	1.9	(0.4)	—
Depreciation and amortization	(617.0)	(577.3)	(545.3)
Impairments	(198.2)	(365.8)	(17.1)
Loss on secured term loan receivable	(52.9)	—	—
Gain on litigation settlement	—	—	26.0
Operating income	$ 187.9	$ 163.9	$ 299.5

The table below represents information about segment assets(in millions):

Segment Identifiable Assets:	December 31, 2019	December 31, 2018
Permian	$ 2,281.1	$ 2,096.8
North Texas	1,135.8	1,308.2
Oklahoma	3,035.0	3,209.5
Louisiana	2,562.0	2,734.5
Corporate	120.7	222.3
Total identifiable assets	$ 9,134.6	$ 9,571.3

(15) 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
2019					
Revenues	$ 1,779.2	$ 1,710.0	$ 1,408.0	$ 1,155.7	$ 6,052.9
Impairments	$ —	$ —	$ —	$ 198.2	$ 198.2
Operating income (loss)	$ 110.6	$ 53.4	$ 96.7	$ (72.8)	$ 187.9
Net income (loss) attributable to ENLK	$ 62.8	$ 4.1	$ 42.4	$ (163.6)	$ (54.3)
2018					
Revenues	$ 1,761.7	$ 1,764.7	$ 2,114.3	$ 2,058.3	$ 7,699.0
Impairments	$ —	$ —	$ 24.6	$ 341.2	$ 365.8
Operating income (loss)	$ 106.6	$ 150.1	$ 92.5	$ (185.3)	$ 163.9
Net income (loss) attributable to ENLK	$ 64.3	$ 111.5	$ 48.8	$ (225.1)	$ (0.5)
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 ENLK	$ 16.7	$ 30.4	$ 27.8	$ 78.8	$ 153.7

(16) Supplemental Cash Flow Information

The following schedule summarizes cash paid for interest and income taxes and non-cash investing activities for the periods presented (in millions):

	Year Ended December 31,		
Supplemental disclosures of cash flow information:	**2019**	**2018**	**2017**
Cash paid for interest (1)	$ 218.5	$ 182.6	$ 163.8
Cash paid for income taxes	$ 3.9	$ 1.5	$ 4.8
Non-cash investing activities:			
Non-cash accrual of property and equipment	$ (6.5)	$ 6.8	$ (22.7)
Discounted secured term loan receivable from contract restructuring	$ —	$ 47.7	$ —

(1) Includes cash paid to ENLC for interest of $62.6 million for the year ended December 31, 2019.

(17) Other Information

The following tables present additional detail for other current assets and other current liabilities, which consists of the following (in millions):

Other current assets:	**December 31, 2019**	**December 31, 2018**
Natural gas and NGLs inventory	$ 43.4	$ 41.3
Secured term loan receivable from contract restructuring, net of discount of $1.1 at December 31, 2018 (1)	—	19.4
Prepaid expenses and other	13.5	12.1
Natural gas and NGLs inventory, prepaid expenses, and other	$ 56.9	$ 72.8

(1) In late May 2019, White Star, the counterparty to our $58.0 million second lien secured term loan receivable, filed for reorganization under Chapter 11 of the U.S. Bankruptcy Code and was not able to repay the outstanding amounts owed to us under the second lien secured term loan. For additional information regarding this transaction, refer to "Note 2—Significant Accounting Policies."

Other current liabilities:	**December 31, 2019**	**December 31, 2018**
Accrued interest	$ 32.6	$ 37.3
Accrued wages and benefits, including taxes	25.5	37.2
Accrued ad valorem taxes	28.5	28.1
Capital expenditure accruals	42.4	50.6
Onerous performance obligations	—	9.0
Short-term lease liability	21.1	1.5
Suspense producer payments	13.8	34.6
Operating expense accruals	10.8	10.2
Other	27.0	38.2
Other current liabilities	$ 201.7	$ 246.7

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, 2019), 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, 2019 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.

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 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 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 officersof our general partner. Executive officers and directors serve until their successors are duly appointed or elected.

Name	Age	Position with EnLink Midstream GP, LLC
Barry E. Davis	58	Chairman and Chief Executive Officer
Eric D. Batchelder	48	Executive Vice President, Chief Financial Officer, and Director
Benjamin D. Lamb	40	Executive Vice President and Chief Operating Officer
Alaina K. Brooks	45	Executive Vice President, Chief Legal and Administrative Officer, Secretary, and Director

Barry E. Davis, Chairman and Chief Executive Officer, has served in this position since August 2019, after serving as Executive Chairman from January 2018 to August 2019, as Chairman and Chief Executive Officer from September 2016 until January 2018, and as President and Chief Executive Officer from our formation until September 2016. Mr. Davis has also served as a director since the initial public offering of Crosstex Energy, L.P. in December 2002. Mr. Davis 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., the predecessor to ENLC. Prior to forming our predecessor entity, 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. In addition to serving on our Board of Directors, Mr. Davis is a Trustee of Texas Christian University (TCU) and a board member of the Kirby Corp. and several other civic and nonprofit organizations. 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 Board to conclude that he should serve as a director.

Eric D. Batchelder, Executive Vice President and Chief Financial Officer, has served in this position since January 2018. Mr. Batchelder was appointed as a director on the Board in August 2019. Prior to January 2018, 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. Mr. Batchelder was elected to serve as a director due to, among other factors, his accounting and financial expertise and his leadership skills.

Benjamin D. Lamb, Executive Vice President and Chief Operating Officer, has served in this position since June 2018. Mr. Lambpreviously served in a number of leadership roles, most recently as Executive Vice President—North Texas and Oklahoma from February 2018 to June 2018 and previously as Executive Vice President—Corporate Development, Senior Vice President—Finance and Corporate Development, and Vice President—Finance from December 2012 to February 2018. Prior to December 2012, 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, Executive Vice President, Chief Legal and Administrative Officer, and Secretary has served in this position since June 2018. Ms. Brooks was appointed as a director on the Board in January 2019. Ms. Brooks previously served in a number of leadership roles, most recently as Senior Vice President, General Counsel and Secretary from September 2014 until June 2018 and as Deputy General Counsel until September 2014. In Ms. Brooks' current role, she serves on our Executive Leadership Team and leads the legal, regulatory, public and industry affairs, environmental health and safety, contract administration, and human resources functions. Prior to 2008, Ms. Brooks practiced law at Weil, Gotshal & Manges LLP and Baker Botts L.L.P., 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. Ms. Brooks was elected to serve as a director due to, among other factors, her legal and human resources experience in the midstream energy industry.

Independent Directors

Following the Merger, we do not have securities listed on the NYSE or any other national securities exchange and are no longer subject to the rules of the NYSE, including rules that require independent directors on the Board. As a result, as of immediately following the Merger, we do not have any independent directors on the Board.

Board Committees

Following the Merger, we do not have securities listed on the NYSE or any other national securities exchange and are no longer subject to the rules of the NYSE, including rules that require an audit committee. Therefore, following the Merger, the Board does not have any standing committees, including an audit committee. The Audit Committee (the "Manager Audit Committee") of the board of directors of the managing member of ENLC (the "Manager Board"), which is comprised of James C. Crain, Leldon E. Echols, and Kyle D. Vann, is responsible for overseeing 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 members of the Manager Audit Committee qualify as "independent" under special standards established by the Commission for members of audit committees, and the Manager Audit Committee includes at least one member who is determined by the Manager Board to meet the qualifications of an "audit committee financial expert" in accordance with Commission rules, including that the person meets the relevant definition of an "independent" director. Leldon E. Echols is an independent director of the Manager Board who has been determined by the Manager Board to be an audit committee financial expert. Unitholders should understand that this designation is a disclosure requirement of the Commission related to the experience and understanding of directors 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 Manager Audit Committee and the Manager Board, and the designation of a director as audit committee financial expert pursuant to this Commission requirement does not affect the duties, obligations, or liabilities of any other member of the Manager Audit Committee or the Manager Board.

Code of Ethics

Our general partner has adopted a Code of Business Conduct and Ethics (the "Code of Ethics") applicable to all of our employees, officers, and directorsThe 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 Commission and other public communications. A copy of the Code of Ethics is 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 Commission.

Delinquent Section 16(a) Reports

For periods prior to the closing of the Merger, at which point we no longer had publicly held common units, Section 16(a) of the Securities Exchange Act of 1934 required our directors, executive officers, and beneficial owners of more than 10% of our common units to file with the Commission 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 2019, 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 (i) one Form 4 filing for each of Matthew C. Harris, William A. Woodburn, and William J. Brilliant, which forms each reported one transaction and were due on January 29, 2019 but were filed January 30, 2019, and (ii) one Form 4 filing for Goldman Sachs Group Inc., which form reported twenty-one transactions in our common units for periods from March 15, 2018 through January 23, 2019 and was due March 19, 2018 (with subsequent due dates after that point up to January 25, 2019) but was filed August 14, 2019.

Item 11. Executive Compensation

Compensation Committee Report

As discussed below, our named executive officers are also named executive officers of ENLC, and the compensation of the named executive officers disclosed herein reflects total compensation for services with respect to ENLC and all subsidiaries of ENLC, including ENLK. The Governance and Compensation Committee of the Manager Board (the "Manager Committee") evaluates and makes recommendations to the Manager Board regarding ENLC's named executive officer compensation. In addition, effective as of the Merger, the Board is composed entirely with named executive officers of ENLK. Due to the foregoing, the Board does not have a standing compensation committee and, instead, the Manager Committee evaluates and makes recommendations to the Board regarding ENLK's named executive officer compensation and has otherwise assumed and will discharge the duties previously discharged by the former Compensation Committee of the Board.

Kyle D. Vann and Leldon E. Echols, who serve on the Manager Committee, are independent directors of the Manager Board in accordance with NYSE standards. The Manager Committee has reviewed and discussed with management the following section titled "Compensation Discussion and Analysis." Based upon its review and discussions, the Manager 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 Manager Committee:

Kyle D. Vann (Chairman)

William J. Brilliant

Leldon E. Echols

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.Our general partner manages our operations and activities, and the Board and officers make decisions on our behalf. The compensation of the named executive officers and directors of our general partneris determined by the Board upon the recommendation of the Manager Committee. Our named executive officers also serve as named executive officers of EnLink Midstream Manager, LLC, the managing member of ENLC. Therefore, the compensation of the named executive officers discussed below reflects total compensation for services with respect toENLC and all of its subsidiaries.

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 Manager Committee's responsibility to design and administer compensation programs that achieve these goals, and to make recommendations to the Board and the Manager Board to approve and adopt these programs. The total compensation of each of our executives is generally comprised of 60% equity-based awards issued under our long-term incentive plan, 20% annual bonus awarded under the Short-Term Incentive Program (the "STI Program"), and 20% base salary.

The Manager 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 plan should represent a significant portion of the executive's total compensation in order to retain and incentivize highly qualified executives and to ensure all executives have a meaningful equity stake in us. Equity-based awards foster a culture of ownership and are a way to align the interests of executives with those of our unitholders;

- The compensation program should be sufficiently flexible to address special circumstances, including retention initiatives 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

The Manager Committee annually 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 the general partner of ENLK. The Manager Committee recommended to the Board adjustments to the compensation program and to each individual element as determined necessary to achieve our goals. The Manager Committee retains a compensation consultant to assist in itsreview and to provide input regarding the compensation program and each individual element.

Role of Compensation Consultant

The Manager Committee retained Meridian Compensation Partners, LLC ("Meridian") as its independent compensation consultant to conduct a compensation review and advise the Manager Committee on certain matters relating to compensation programs applicable to the named executive officers and other employees ofour general partner during 2019. In particular, Meridian assisted the Manager 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 Manager Committee about emerging best practices and changes in the regulatory and governance environment. Meridian provided information to the Manager Committee regarding our compensation programs for 2019. Meridian's work for the Manager Committee did not raise any conflicts of interest in 2019.

During 2019, the Manager Committee decided to initiate a process to evaluate the effectiveness of its current compensation consultant and potentially engage a new compensation consultant. The Manager Committee asked a number of compensation consultants, including Meridian, to participate in a request for proposal process. After reviewing the proposals and interviewing the participating consulting firms, the Manager Committee elected to engage Mercer (US) Inc., an independent consulting firm ("Mercer"). Mercer was formally engaged by the Manager Committee in June 2019, and since that time, Mercer has assisted theManager Committee with compensation items related to 2020.

Role of Peer Group and Benchmarking

For 2019, the Manager Committee and Meridian collaborated to identify the following companies as our peer companies: Andeavor, Boardwalk Pipeline Partners, L.P., Buckeye Partners, L.P., Cheniere Energy, Inc., Enable Midstream Partners, LP, Energy Transfer Partners, L.P., Genesis Energy, L.P., HollyFrontier Corp., Magellan Midstream Partners, L.P., NuStar Energy L.P., ONEOK Inc., Targa Resources Corp., and The Williams Cos. Inc. (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 Manager 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 Manager Committee, with the assistance of the compensation consultant, 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 Manager 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, the compensation consultant provides guidance on current industry trends and best practices to the Manager Committee relating to all aspects of executive compensation.

While compensation surveys and Peer Group data are considered, the Manager 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 Manager Committee of our performance relative to expectations and actual market/business conditions.

Elements of Compensation

For fiscal year 2019, 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 Manager 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 Manager 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 the compensation consultant, compensation surveys, and performance and responsibilities of the named executive officers. The base salaries approved by the Board and paid to our named executive officers for fiscal year 2019 (and payable for fiscal 2020) are as follows:

	Prior Salary	Base Salary Effective For 2020	Percent Increase (Decrease)
Barry E. Davis (1)	$ 735,000	$ 748,000	1.8 %
Benjamin D. Lamb	$ 491,625	$ 501,000	1.9 %
Eric D. Batchelder	$ 450,225	$ 458,000	1.7 %
Alaina K. Brooks	$ 439,875	$ 450,000	2.3 %
Michael J. Garberding (2)	$ 675,000	$ —	(100.0)%

(1) In August 2019, Mr. Davis, formerly our Executive Chairman, was named Chairman and Chief Executive Officer.

(2) In August 2019, Mr. Garberding departed from his position as President and Chief Executive Officer. In September 2019, Mr. Garberding left the Company.

Bonus Awards. The Manager Board and the Manager Committee 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 success and are subject to the discretion of the Manager Board and the Manager Committee. 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 2019 and associated information are as follows:

Component	Description	Weighting
Financial	Adjusted EBITDA and distributable cash flow (“DCF”) per unit to maximize financial performance	50% Adjusted EBITDA 10% DCF per unit
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 and 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” 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 Manager Board and the Manager Committee to determine the bonus amounts that are ultimately payable under the STI Program, including to the named executive officers, as further described below.

The Manager Committee and the Manager Board, with input from management, set the annual weightings for each Primary Bonus Component, any additional weightings that apply with respect to the features comprising a particular Primary Bonus Component, and the “threshold/target/maximum” standard that applies to the Primary Bonus Components. This standard is 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 Manager Board, based on recommendations of the Manager Committee, initially establishes the target bonus awards that may be earned and ultimately determines the final bonus amounts, if any, that are payable under the STI Program for the named executive officers. Initial bonus award amounts for consideration by the Manager Committee and the Manager Board 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 earnings (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 Manager Committee believes that a portion of executive compensation for named executive officers must remain discretionary. Therefore, the STI Program contemplates that the Manager Committee and the Manager Board retain discretion with respect to target bonus awards and the final bonus amounts for named executive officers. In this regard, the Manager Committee may exercise such discretion to recommend to the Manager Board 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 Manager Board based upon the Manager Committee's 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 Manager Committee as a whole. All named executive officers met or exceeded their minimum personal performance objectives for 2019. Accordingly, the Manager Committee and the Manager Board awarded bonuses to the named executive officers as follows:

	Target Bonus Percentage (as a % of Base Salary)	2019 Bonus (as a % of Base Salary)	2019 Bonus Amount ($)
Barry E. Davis (1)	125 %	87 %	636,568
Benjamin D. Lamb	100 %	106 %	521,207
Eric D. Batchelder	90 %	95 %	429,585
Alaina K. Brooks	90 %	101 %	444,709
Michael J. Garberding (2)	100 %	83 %	560,463

(1) In August 2019, Mr. Davis, formerly our Executive Chairman, was named Chairman and Chief Executive Officer. In association with this transition, the target bonus percentage for Mr. Davis increased from 90% to 125%.
(2) In August 2019, Mr. Garberding departed from his position as President and Chief Executive Officer. In September 2019, Mr. Garberding left the Company.

Target adjusted EBITDA is based upon a standard of reasonable market expectations and our performance and varies from year to year. For2019, our adjusted EBITDA levels for bonuses were $1,055 million for minimum threshold bonuses, $1,131 million for target bonuses, and $1,225 million for maximum bonuses. For 2019, 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. Prior to the Merger, our named executive officers and outside directors were eligible to receive awards under the EnLink Midstream GP, LLC Long-Term Incentive Plan (the "GP Plan"). Our named executive officers and outside directors are also eligible to participate in the EnLink Midstream, LLC 2014 Long-Term Incentive Plan (the "2014 Plan"). The Board, upon the recommendation of the Manager Committee, approves the grants of equity awards to our named executive officers. The Manager Committee believes that equity awards should comprise a significant portion of a named executive officer's total compensation. A number of factors are considered when determining grants to each individual named executive officer including but not limited to: compensation surveys, Peer Group data, the named executive officer's individual performance, company performance, market conditions, succession planning, retention, and other factors as determined by the Manager Committee and/or the Manager Board.

A brief discussion of each plan follows:

EnLink Midstream GP, LLC Long-Term Incentive Plan. Our general partner adopted the GP Plan for employees, consultants, and independent contractors of our general partner and its affiliates and outside directors of the Board who perform services for us. No additional grants of equity awards will be made under the GP Plan for periods after the Merger. The 3,416,046 common units (denominated for purposes of this sentence as ENLC common units) that remained eligible for future grants under the GP Plan immediately prior to the effective time of the Merger the "Rollover Units") are included among the ENLC common units available for grant under the 2014 Plan. In determining this number of the Rollover Units (i.e., the 3,416,046 ENLC common units specified above), certain assumptions were made regarding the number of units issuable pursuant to any awards under the GP Plan that were outstanding immediately prior to the effective time of the Merger. For instance, it was assumed that performance metrics, as and when applicable under such awards, would be satisfied in the future at their maximum levels, thereby resulting in the greatest amount of units being issued pursuant to such awards.

Effective as of the closing of the Merger, each unit-based award issued and outstanding immediately prior to the effective time of the Merger under the GP Plan has been converted into an award with respect to ENLC common units with substantially similar terms as were in effect immediately prior to the effective time, with certain adjustments to the performance-based vesting terms for any applicable awards related to the performance of ENLC and ENLK (as further described below). In addition, as of the closing of the Merger (i) ENLC assumed all obligations in respect of the GP Plan, and (ii) the Manager Committee (and the Manager Board when applicable) became responsible for the administration of the GP Plan. It is anticipated that no future awards will be granted under the GP Plan.

Upon a change of control for purposes of the GP Plan and subject to the terms and conditions of the applicable award agreements thereunder, the outstanding options may become exercisable and the outstanding restricted incentive units may become vested upon the change of control or a qualifying termination of employment thereafter. The closing of the GIP Transaction constituted a change of control for such purposes, and the terms and conditions of the performance-based restricted incentive unit awards provided for accelerated vesting upon such change of control. However, certain officers waived the accelerated vesting of their performance-based restricted incentive unit awards, such that, the waived awards remain outstanding and subject to vesting based on the performance metrics and termination conditions specified in the applicable awards (as amended in connection with such waiver).

EnLink Midstream, LLC Long-Term Incentive 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"), Distribution Equivalent Rights ("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. The 2014 Plan was subsequently amended and restated (i) effective as of January 20, 2019 to increase the number of common units reserved for issuance thereunder to 17,700,000 units, and (ii) effective as of January 25, 2019 to reflect certain transactions described in the Merger Agreement including the inclusion of the Rollover Units among the common units available for issuance 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 21,116,046 common units that may be awarded under the 2014 Plan, 14,865,181 common units remain eligible for future grants as of December 31, 2019. 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, as currently amended and restated, will automatically expire on December 30, 2028. 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.

With respect to awards, upon a change of control of us 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. The closing of the GIP Transaction constituted a change of control for such purposes, and the terms and conditions of the performance-based restricted incentive unit awards provided for accelerated vesting upon such change of control.

However, certain officers waived the accelerated vesting of their performance-based restricted incentive unit awards, such that the waived awards remain outstanding and subject to vesting based on the performance metrics and termination conditions specified in the applicable awards (as amended in connection with such waiver).

For more information on the 2014 Plan and the GP Plan, see ENLC's Information Statement on Schedule 14C filed with the Commission on December 31, 2018 and our Annual Report on Form 10-K for the year ended December 31, 2018, filed with the Commission on February 20, 2019.

Performance Unit Awards. Beginning in 2015, the managing member of ENLC and our general partner granted performance awards under the 2014 Plan and the GP Plan, respectively. The performance award agreements provide that the vesting of restricted incentive units granted under the GP Plan and the 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. As of the effective time of the Merger, the performance metric for any then outstanding performance award was modified such that, the performance metric will, on a weighted average basis, (i) continue to relate to the EnLink TSR relative to the TSR performance of the Peer Companies in respect of periods preceding the effective time of the Merger; and (ii) relate solely to the TSR performance of ENLC relative to the TSR performance of such Peer Companies in respect of periods after the effective time of the Merger.

On March 8, 2019, the Manager Board approved new forms of the performance-based award agreements ("the "Performance-Based Award Agreement") for future awards of equity-based compensation under the 2014 Plan. The Performance-Based Award Agreement provides that the vesting of restricted incentive units under the 2014 Plan is dependent on the achievement of (i) certain TSR performance goals relative to the TSR achievement of a peer group of companies and (ii) performance goal based on cash flow ("Cash Flow"). At the time of grant, the Board will determine the relative weighting of the two performance goals by including in the relevant Performance-Based Award Agreement the number of Restricted Units that will be eligible for vesting depending on the achievement of the TSR performance goals (the "Total TSR Units") and the achievement of the Cash Flow performance goals (the "Total CF Units").

The Performance-Based Award Agreement provides for four separate performance periods: (i) three performance periods are each of the first, second, and third calendar years that occur following the vesting commencement date of the Performance-Based Award Agreement and (ii) the fourth performance period is the cumulative three-year period from the vesting commencement date through the third anniversary thereof (the "Cumulative Performance Period").

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 0% to 200% of the units granted depending on EnLink's achievement of performance goals 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. In connection with the GIP Transaction, certain outstanding performance unit agreements issued prior to the close of the transaction were modified to delay vesting in exchange for an increase in the minimum vesting of units from zero to 100% as described in our Current Report on Form 8-K filed with the Commission on July 23, 2018. 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% restricted incentive units and 50% performance units on an annual basis. In addition, our executive officers may receive additional grants of equity compensation in certain circumstances, such as promotions and change of ownership. All performance and restricted incentive units that we grant are charged against earnings according to ASC 718.

Anti-Hedging Policy. Pursuant to ENLC's insider trading policy, ENLC prohibits hedging of its securities by directors, officers, or employees and pledging of its securities as collateral by directors and executive officers.

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. The Operating

Partnership maintains a tax-qualified 401(k) retirement plan that provides eligible employees with an opportunity to save for retirement on a tax deferred basis. In 2019, the Operating Partnership matched 100% of every dollar contributed for contributions of up to 6% of eligible compensation made by eligible participants plus a discretionary profit-sharing 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

In 2019, all of our named executive officers and certain members of senior management entered into amended and restated forms of change in control agreements (the "Change in Control Agreements") with the Operating Partnership and amended and restated forms of severance agreements (the "Severance Agreements" and collectively with the Change in Control Agreements, the "Agreements") with the Operating Partnership, which were approved by the Manager Board in September 2019. 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, the managing member of ENLC, the Operating Partnership, ENLC, 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 claw back 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 Chairman and Chief Executive Officer 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 Initial Expiration Date (as defined in the Severance Agreement), which is generally a term of one year from 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 Initial Expiration Date (each, a "Renewal Date"), unless the Board 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 with automatic renewal on each anniversary of the execution date until (i) termination by the Board providing 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 GP Plan and the 2014 Plan, the amounts to be received by our named executive officers in the event of a change of control (as defined in such 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 such 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 Manager Committee.

Upon a change of control, and except as provided in the 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 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.

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, 2019 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 and the Manager Board, upon recommendation of the Manager Committee, determines the compensation payable to each of the named executive officers. None of the named executive officers serves as a member of the Manager Committee. The Chairman and Chief Executive Officer makes recommendations regarding the compensation of his leadership team with the Manager Committee, including specific recommendations for each element of compensation for each of the named executive officers. The Chairman and Chief Executive Officer 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.

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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 ($)
Barry E. Davis (3)	2019	556,000	636,568	4,553,287 (6)	744,456 (7)	6,490,311
Chairman and Chief Executive Officer	2018	529,000	784,367	3,835,864	784,034	5,933,265
	2017	695,000	960,000	4,533,371	565,075	6,753,446
Benjamin D. Lamb	2019	491,200	521,207	1,264,284	362,424 (8)	2,639,115
Executive Vice President and Chief Operating Officer	2018	447,500	665,733	4,272,801	703,111	6,089,145
	2017	345,000	345,000	1,431,552	274,563	2,396,115
Eric D. Batchelder	2019	449,900	429,585	948,218	205,157 (9)	2,032,860
Executive Vice President and Chief Financial Officer	2018	399,200	560,771	3,133,675	304,836	4,398,482
Alaina K. Brooks (4)	2019	439,500	444,709	902,261	302,253 (10)	2,088,723
Executive Vice President, Chief Legal and Administrative Officer, and Secretary	2018	393,300	468,087	2,410,163	204,661	3,476,211
Michael J. Garberding (5)	2019	528,200	560,463	2,844,635	5,486,256 (11)	9,419,554
President and Chief Executive Officer	2018	646,600	1,009,247	7,975,169	727,195	10,358,211
	2017	500,000	500,000	2,147,374	396,190	3,543,564

(1) Bonuses include all annual bonus payments. For 2019, the named executive officers received bonuses in the form of 35% cash and 65% equity awards that immediately vest. For 2018, the named executive officers received bonuses in the form of 50% cash and 50% equity awards that immediately vest. Such equity awards were entirely allocated in restricted incentive units of ENLC. For 2017, the named executive officers received bonuses in the form of 25% cash and 75% equity awards that immediately vest. Such equity awards were allocated 50% in restricted incentive units of ENLK and 50% in restricted incentive units of ENLC. Equity awards for 2019, 2018, and 2017 represent the grant date fair value of awards computed in accordance with ASC 718.
(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 10" for the assumptions made in our valuation of such awards.
(3) In August 2019, Mr. Davis, formerly our Executive Chairman, was named Chairman and Chief Executive Officer.
(4) Ms. Brooks became a named executive officer in fiscal year 2018, and, therefore, summary compensation information is presented only for fiscal years 2018 and 2019.
(5) In August 2019, Mr. Garberding departed from his position as President and Chief Executive Officer. In September 2019, Mr. Garberding left the Company.
(6) In connection with assuming his role as Chairman and Chief Executive Office in August 2019, Mr. Davis received a one-time transition grant of restricted incentive units and performance unit awards of $1,000,000 and $1,972,936, respectively.
(7) Amount of all other compensation for Mr. Davis includes a matching 401(k) contribution of $16,800, DERs with respect to restricted incentive units of ENLK in the amount of $325,786, and DERs with respect to restricted incentive units of ENLC in the amount of $401,870.
(8) Amount of all other compensation for Mr. Lamb includes a matching 401(k) contribution of $16,800, DERs with respect to restricted incentive units of ENLK in the amount of $55,107, and DERs with respect to restricted incentive units of ENLC in the amount of $290,517.
(9) Amount of all other compensation for Mr. Batchelder includes a matching 401(k) contribution of $16,800, DERs with respect to restricted incentive units of ENLK in the amount of $30,526, and DERs with respect to restricted incentive units of ENLC in the amount of $157,831.
(10) Amount of all other compensation for Ms. Brooks includes a matching 401(k) contribution of $16,800, DERs with respect to restricted incentive units of ENLK in the amount of $97,839, and DERs with respect to restricted incentive units of ENLC in the amount of $187,614.
(11) Amount of all other compensation for Mr. Garberding includes a matching 401(k) contribution of $16,800, DERs with respect to restricted incentive units of ENLK in the amount of $250,046, and DERs with respect to restricted incentive units of ENLC in the amount of $935,623. Mr. Garberding received $4,283,788 in connection with his departure.

CEO Pay Ratio

For fiscal year 2019, the annual total compensation for Mr. Davis was $5,403,924 and for the median employee was $117,456. The resulting ratio of annual total compensation of Mr. Davis to the annual total compensation of our median employee was 46:1. 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 the median employee by examining 2019 W-2 Box 1 Federal Taxable Wages (the "Taxable Wages Measure") for all of our employees, excluding the Chairman and Chief Executive Officer, who were employed on December 31, 2019, the last business day of the 2019 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 2019. 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 2019 Summary Compensation Table above. We calculated annual total compensation for the CEO by annualizing Mr. Davis's salary in his role as Chairman and Chief Executive Officer, given that Mr. Davis transitioned from Executive Chairman to Chairman and Chief Executive Officer in August 2019.

Narrative Disclosure to Summary Compensation Table

A narrative description of all material factors necessary to an understanding of the information included in the above Summary Compensation Table is included in the section titled "Compensation Discussion and Analysis" and in the footnotes to such tables.

Grants of Plan-Based Awards for Fiscal Year 2019 Table

The following table provides information concerning each grant of an award made to a named executive officer for fiscal year2019, including, but not limited to, awards made under the 2014 Plan.

ENLINK MIDSTREAM, LLC—GRANTS OF PLAN-BASED AWARDS

		Estimated Future Payouts Under Equity Incentive Plan Awards					
Name	**Grant Date**	**Threshold (#)**	**Target (#)**	**Maximum (#)**	**All Other Unit Awards: Number of Units**		**Grant Date Fair Value of Unit Awards ($)(1)**
Barry E. Davis	3/12/2019	60,328	120,656	241,312	—	(2)	1,580,351
	10/9/2019	—	—	—	135,318	(3)	1,000,000
	10/9/2019	135,318	270,636	541,272	—	(4)	1,972,936
Benjamin D. Lamb	3/12/2019	48,263	96,525	193,050	—	(2)	1,264,284
Eric D. Batchelder	3/12/2019	36,197	72,394	144,788	—	(2)	948,218
Alaina K. Brooks	3/12/2019	28,958	57,915	115,830	—	(2)	758,571
	6/19/2019	7,240	14,479	28,958	—	(2)	143,690
Michael J. Garberding (5)	3/12/2019	108,591	217,181	434,362	—	(2)	2,844,635

(1) 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 Data— Note 10" for the assumptions made in our valuation of such awards.
(2) 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, 2022, recipients receive DERs, if any, with respect to the number of performance awards vested.
(3) In connection with assuming his role as Chairman and Chief Executive Office in August 2019, Mr. Davis received a one-time transition grant of restricted incentive units. These awards include DERs that provide for distributions on restricted incentive units if made on unrestricted common units during the restriction period unless otherwise forfeited and vest 100% on August 1, 2022.
(4) In connection with assuming his role as Chairman and Chief Executive Office in August 2019, Mr. Davis received a one-time transition grant of performance unit awards. These awards 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 August 1, 2022, recipients receive DERs, if any, with respect to the number of performance awards vested.
(5) In August 2019, Mr. Garberding departed from his position as President and Chief Executive Officer. In September 2019, Mr. Garberding left the Company.

Outstanding Equity Awards at Fiscal Year-End Table for Fiscal Year2019

The following table provides information concerning all outstanding equity awards made to a named executive officer as ofDecember 31, 2019, including, but not limited to, awards made under the 2014 Plan and the GP Plan.

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 ($)(2)	Equity Incentive Plan Awards: Number of Unearned Units or Other Rights that Have Not Vested (#)(3)(4)(5)	Equity Incentive Plan Awards: Market or Payout Value of Unearned Units or Other Rights That Have Not Vested ($)(2)
Barry E. Davis	2022	135,318	829,499	391,292 (6)	2,398,620
	2021	98,730	605,215	98,730	605,215
	2020	106,667	653,869	106,667	653,869
Benjamin D. Lamb	2022	—	—	96,525	591,698
	2021	139,925	857,740	—	—
	2020	159,364	976,901	—	—
Eric D. Batchelder	2022	—	—	72,394	443,775
	2021	115,245	706,452	—	—
	2020	47,777	292,873	—	—
Alaina K. Brooks	2022	—	—	72,394	443,775
	2021	73,780	452,271	26,000	159,380
	2020	67,427	413,328	19,649	120,448
Michael J. Garberding (7)	2022	—	—	48,152	295,172

(1) Restricted incentive units vesting in 2020 and 2021 vest on January 1st and August 1st of the relevant year, as applicable. Restricted incentive units vesting in 2022 vest on January 1st. For Mr. Davis, restricted incentive units vesting in 2022 vest on January 1st and August 1st, as applicable.
(2) The closing price for the ENLC common units was $6.13 as of December 31, 2019.
(3) Reflects the target number of performance units granted to the named executive officers multiplied by a performance percentage of 100%.
(4) Vesting of awards in 2021 and 2022 are contingent upon (i) the EnLink TSR performance measured against a peer group of companies in respect of periods preceding the effective time of the Merger and (ii) the TSR performance of ENLC measured against a peer group of companies in respect of periods after the effective time of the Merger.
(5) Vesting of awards in 2022 are contingent upon (i) the EnLink TSR performance measured against a peer group of companies and (ii) EnLink's achieved distributable cash flow per unit outstanding.
(6) Vesting of awards in August 2020 for Mr. Davis are contingent upon the EnLink TSR performance measured against a peer group of companies.
(7) In August 2019, Mr. Garberding departed from his position as President and Chief Executive Officer. In September 2019, Mr. Garberding left the Company. Pursuant to his departure, Mr. Garberding's outstanding restricted incentive units vested and a portion of his outstanding performance units vested at 100% in 2019. The remaining outstanding performance units not vested in 2019 will vest on the original vesting date of January 1, 2022.

Units Vested Table for Fiscal Year 2019

The following tables provide information related to the vesting of restricted units and restricted incentive units during fiscal year ended 2019.

ENLINK MIDSTREAM GP, LLC—UNITS VESTED

Name	Date Vested (1)	Number of Units Acquired on Vesting	Value Per Unit Realized on Vesting ($)	Total ($)
Barry E. Davis	1/1/2019	128,145	11.01	1,410,876
	2/14/2019	61,277	12.49	765,293
Benjamin D. Lamb	1/1/2019	53,588	11.01	590,004
Eric D. Batchelder	—	—	—	—
Alaina K. Brooks	1/1/2019	13,429	11.01	147,853
	2/14/2019	14,127	12.49	176,442
Michael J. Garberding (2)	1/1/2019	82,712	11.01	910,659
	2/14/2019	35,540	12.49	443,870

(1) Units listed as vesting after the closing of the Merger vested as ENLC units with the amount adjusted to be 1.15 ENLC units for each unit listed.

(2) In August 2019, Mr. Garberding departed from his position as President and Chief Executive Officer. In September 2019, Mr. Garberding left the Company. Pursuant to his departure, Mr. Garberding's outstanding restricted incentive units vested and a portion of his outstanding performance units vested at 100% in 2019. The remaining outstanding performance units not vested in 2019 will vest on the original vesting date of January 1, 2022.

ENLINK MIDSTREAM, LLC—UNITS VESTED

Name	Date Vested	Number of Units Acquired on Vesting	Value Per Unit Realized on Vesting ($)	Total ($)
Barry E. Davis	1/1/2019	110,709	9.49	1,050,628
	2/14/2019	52,938	10.86	574,907
	3/6/2019	34,645	11.32	392,181
Benjamin D. Lamb	1/1/2019	46,296	9.49	439,349
	3/6/2019	29,405	11.32	332,865
Eric D. Batchelder	3/6/2019	24,769	11.32	280,385
Alaina K. Brooks	1/1/2019	14,286	9.49	135,574
	2/14/2019	15,028	10.86	163,204
	3/6/2019	20,675	11.32	234,041
Michael J. Garberding (1)	1/1/2019	71,457	9.49	678,127
	2/14/2019	30,704	10.86	333,445
	3/6/2019	44,578	11.32	504,623
	9/2/2019	534,779	7.94	4,246,145

(1) In August 2019, Mr. Garberding departed from his position as President and Chief Executive Officer. In September 2019, Mr. Garberding left the Company. Pursuant to his departure, Mr. Garberding's outstanding restricted incentive units vested and a portion of his outstanding performance units vested at 100% in 2019. The remaining outstanding performance units not vested in 2019 will vest on the original vesting date of January 1, 2022.

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, 2019.

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)
Barry E. Davis	3,994,068	34,150	—	5,647,818	5,746,287
Benjamin D. Lamb	2,417,707	33,612	—	2,417,707	2,426,340
Eric D. Batchelder	2,190,440	24,067	—	2,190,440	1,443,100
Alaina K. Brooks	2,166,234	31,288	—	2,166,234	1,589,203
Michael J. Garberding (6)	—	—	—	—	—

(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 or she is terminated without cause (as defined in the Severance Agreement) or if he or she 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 or she is terminated without cause (as defined in the applicable Severance Agreement or Change of Control Agreement (the “Applicable Agreement”) or if he or she terminates employment for good reason (as defined in the Applicable Agreement)).

(3) Each named executive officer is entitled to his or her 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 or she is terminated for cause (as defined in the Applicable Agreement) or he or she 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 Chairman and Chief Executive Officer), the Outplacement Benefit, and when applicable, the bonus amounts comprising the General Benefits will be paid if he or she is terminated without cause (as defined in the Change of Control Agreement) or if he or she terminates employment for good reason (as defined in the Change of Control Agreement) within 120 days prior to or two 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 2019.

(6) In August 2019, Mr. Garberding departed from his position as President and Chief Executive Officer. In September 2019, Mr. Garberding left the Company. Pursuant to his departure, Mr. Garberding received a cash payment of $4,283,788 related to his Severance Benefit, $560,463, which is a prorated amount related to his 2019 bonus at the time the bonus is payable at the end of March 2020, and accelerated vesting of outstanding equity awards valued at $4,246,145 as of the vesting date.

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Compensation of Directors for Fiscal Year 2019

DIRECTOR COMPENSATION

Name	Fees Earned or Paid in Cash ($)	Unit Awards ($)	All Other Compensation ($)(1)	Total ($)
Leldon E. Echols (2)	15,413	—	1,459	16,872
Kyle D. Vann (2)	36,250	—	2,918	39,168
Scott A. Griffiths (2)	37,708	—	2,918	40,626

(1) Other Compensation is comprised of DERs with respect to restricted incentive units.
(2) In connection with the closing of the Merger, each of Messrs. Echols, Griffiths, and Vann departed from their positions as directors.

Barry E. Davis, Eric D. Batchelder, and Alaina K. Brooks, as officers of the Managing Member, receive no separate compensation for their respective service as directors.

Compensation Committee Interlocks and Insider Participation

The Manager Committee is comprised of Kyle D. Vann (Chairman), William J. Brilliant, and Leldon E. Echols. As described elsewhere in this report, Mr. Brilliant is a partner of GIP and may have an interest in the transactions among GIP, ENLC, and us. Please see “Item 13. Certain Relationships and Related Transactions, and Director Independence.”

No other member of the Manager Committee during fiscal 2019 was a current or former officer or employee of our general partner or had any relationship requiring disclosure by us under Item 404 of Regulation S-K as adopted by the Commission. None of our general partner’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 Manager Board or the Manager Committee.

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 reassume his role as the Chairman and Chief Executive Officer in August 2019 was in our best interest, and that such arrangement made the best use of Mr. Davis’ unique skills and experience in the industry.

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 of the Manager Board (the “Manager 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 Manager 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 ENLK as of February 19, 2020, held by:

- each person who is known to ENLK to beneficially own more than 5% of any class of voting units then outstanding;
- all the directors of our general partner;
- each named executive officer of our general partner; and
- all the directors and executive officers of our general partner as a group.

The percentage of total units beneficially owned is based upon a total of144,358,720 common units as of February 19, 2020. Neither the Series B Preferred Units, which are exchangeable on a 1-for-1.15 basis (subject to certain adjustments) for common units of ENLC, nor the Series C Preferred Units, which are perpetual preferred units that are not convertible into common units, are factored into the percentage ownership calculations. None of the named beneficial owners set forth in the table below owns any of the 59,748,549 Series B Preferred Units or the 400,000 outstanding Series C Preferred Units as ofFebruary 19, 2020.

Name of Beneficial Owner (1)	Common Units Beneficially Owned (2)	Percentage of Common Units Beneficially Owned
Global Infrastructure Investors III, LLC (3) (4)	144,358,720	100.00 %
Barry E. Davis	—	— %
Eric D. Batchelder	—	— %
Benjamin D. Lamb	—	— %
Alaina K. Brooks	—	— %
Michael J. Garberding (5)	—	— %
All directors and executive officers as a group (4 persons)	—	— %

(1) Unless otherwise indicated, the beneficial owner has sole voting and dispositive power over all units listed. Unless otherwise indicated, the address of each beneficial owner is 1722 Routh Street, Suite 1300, Dallas, Texas 75201.

(2) Pursuant to Rule 13d-3 under the Exchange Act, a person has beneficial ownership of a security as to which that person, directly or indirectly, through any contract, arrangement, understanding, relationship, or otherwise has or shares voting power and/or investment power of such security and as to which that person has the right to acquire beneficial ownership of such security within 60 days.

(3) ENLC is the record holder of 144,358,720 common units of ENLK. The managing member of ENLC may be deemed to share beneficial ownership of these ENLK common units. GIP III Stetson I, L.P. ("Stetson I") is the sole member of the managing member of ENLC and may be deemed to share beneficial ownership of the ENLK common units beneficially owned by the managing member of ENLC. Based solely on the Amendment No. 2 to the Schedule 13D with the Commission on February 5, 2019 by Global Infrastructure Investors III, LLC ("Global Investors"), Global Investors is the sole general partner of Global Infrastructure GP III, L.P. ("Global GP"), which is the general partner of each of GIP III Stetson Aggregator I, L.P. ("Aggregator I") and GIP III Stetson Aggregator II, L.P. ("Aggregator II"), which are the managing members of GIP III Stetson GP, LLC ("Stetson GP"), which is the general partner of Stetson I. As a result, Global Investors, Global GP, Aggregator I, Aggregator II, and Stetson GP may be deemed to share beneficial ownership of the ENLK common units beneficially owned by Stetson I. Adebayo Ogunlesi, Jonathan Bram, William Brilliant, Matthew Harris, Michael McGhee, Rajaram Rao, William Woodburn, Salim Samaha and Robert O'Brien, as the voting members of the Investment Committee of Global Investors, may be deemed to share beneficial ownership of the ENLK common units beneficially owned by Global Investors. Such individuals expressly disclaim any such beneficial ownership. The address of each of Stetson I, Global Investors, Global GP, Aggregator I, Aggregator II, Stetson GP, and Messrs. Ogunlesi, Bram, Brilliant, Harris, McGhee, Rao, Woodburn, Samaha, and O'Brien is c/o Global Infrastructure Management, LLC, 1345 Avenue of the Americas, 30th Floor, New York, New York 10105.

(4) As the indirect owner of 40.3% of the outstanding membership interests in ENLC, and 100% of the outstanding membership interests in ENLC's managing member, GIP may be deemed to beneficially own all common units of ENLK.

(5) In August 2019, Mr. Garberding departed from his position as President and Chief Executive Officer. In September 2019, Mr. Garberding left the Company. The units listed reflect Mr. Garberding's ownership of ENLK common units at the time of his departure.

EnLink Midstream, LLC Ownership

The following table shows the beneficial ownership of ENLC, as ofFebruary 19, 2020, held by:

- all the directors of our general partner;
- each named executive officer of our general partner; and
- all the directors and executive officers of our general partner as a group.

The percentage of total common units of ENLC beneficially owned is based on a total of488,445,794 units as of February 19, 2020.

Name of Beneficial Owner (1)	Common Units Beneficially Owned (2)	Percentage of Common Units Beneficially Owned (3)	ENLC Class C Common Units Beneficially Owned (2)	Percentage of ENLC Class C Common Units Beneficially Owned	Total Units Beneficially Owned (2)	Percentage of Total Units Beneficially Owned (4)
Barry E. Davis (5)	2,922,797	*	—	—	2,922,797	*
Eric D. Batchelder	40,024	*	—	—	40,024	*
Benjamin D. Lamb	298,917	*	—	—	298,917	*
Alaina K. Brooks	71,741	*	—	—	71,741	*
Michael J. Garberding (6)	867,322	*	—	—	867,322	*
All directors and executive officers as group (4 persons)	3,333,479	*	—	—	3,333,479	*

* Less than 1%

(1) The beneficial owner has sole voting and dispositive power over all units listed. The address of each beneficial owner is 1722 Routh Street, Suite 1300, Dallas, Texas 75201.

(2) Pursuant to Rule 13d-3 under the Exchange Act, a person has beneficial ownership of a security as to which that person, directly or indirectly, through any contract, arrangement, understanding, relationship, or otherwise has or shares voting power and/or investment power of such security and as to which that person has the right to acquire beneficial ownership of such security within 60 days.

(3) The percentages reflected in the column below are based on a total of 488,445,794 common units.

(4) The percentages reflected in the column below are based on a total of 557,156,625 common units, which includes the units described in (3) above, and 68,710,831 common units, which reflects the as-exchanged amount of the 59,748,549 ENLC Class C Common Units held by Enfield, which owns the same number of Series B Preferred Units. The Series B Preferred Units are exchangeable into ENLC common units on a 1-for-1.15 basis, subject to certain adjustments. For this reason, the percentages in this column reflect the exchange of the Series B Preferred Units into ENLC common units. Upon any exchange of Series B Preferred Units into ENLC common units, an equal number of ENLC Class C Common Units will be canceled.

(5) Of these ENLC common units, 1,101,424 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.

(6) In August 2019, Mr. Garberding departed from his position as President and Chief Executive Officer. In September 2019, Mr. Garberding left the Company. The units listed reflect Mr. Garberding's ownership of ENLC common units at the time of his departure.

Beneficial Ownership of General Partner Interest

EnLink Midstream GP, LLC owns all of our general partner interest. EnLink Midstream GP, LLC is wholly-owned by ENLC.

GIP's Pledge of Equity Interests in ENLC and the Managing Member of ENLC

GIP has pledged all of the equity interests that it owns in ENLC and ENLC's managing member to its lenders as security under a secured credit facility entered into by a GIP entity in connection with the GIP Transaction (the "GIP Credit Facility"). Although we are not a party to this credit facility, if GIP were to default under the GIP Credit Facility, GIP's lenders could foreclose on the pledged equity interests. Any such foreclosure on GIP's interest would result in a change of control of our general partner and 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. See "Item 1A. Risk Factors—GIP has pledged all of the equity interests that it owns in ENLC and ENLC's managing member to GIP's lenders under its credit facility. A default under GIP's credit facility could result in a change of control of our general partner."

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)	5,381,461 (2)	N/A	14,865,181 (3)
Equity Compensation Plans Not Approved by Security Holders	N/A	N/A	N/A

(1) These plans include both the 2014 Plan, which was approved by ENLC's unitholders in March 2014 for the benefit of ENLC's officers, employees, and directors, and the GP Plan, which was approved by our unitholders effective April 6, 2016 for the benefit of our officers, employees, and directors. As of the closing of the Merger, ENLC assumed all obligations in respect of the GP Plan. See "Item 11—Executive Compensation—Compensation Discussion and Analysis" for additional information regarding the 2014 Plan and the GP Plan.
(2) The number of securities includes 2,574,619 restricted units that have been granted under the 2014 Plan that have not vested and 1,488,986 restricted units that have been granted under the GP Plan that have not vested. In addition, the number of securities includes 1,126,581 performance unit awards that have been granted under the 2014 Plan, assuming the target distribution at the time of vesting, and 191,275 performance unit awards that have been granted under the GP 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. See "Item 11—Executive Compensation—Compensation Discussion and Analysis" for additional information regarding the 2014 Plan and the GP Plan.
(3) Effective as of the closing of the Merger, the 2014 Plan, as amended, provided for the issuance of a total of 21,116,046 common units under the 2014 Plan, inclusive of the Rollover Units that remained eligible for future grants under the GP Plan immediately prior to the effective time of the Merger. No additional grants of equity awards will be made under the GP Plan for periods after the Merger. Of the 21,116,046 common units that may be awarded under the 2014 Plan, 14,865,181 common units remained eligible for future grants as of December 31, 2019.

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

Our General Partner

Our operations 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 in us.

As a result of the Merger, ENLC owns all of our outstanding common units. ENLC also 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 GIP. Therefore, GIP indirectly controls our general partner, which has the sole authority to manage and operate our business. Accordingly, through its control of our general partner, GIP effectively has the ability to control our management. Refer to "Item 8. Financial Statements and Supplementary Information—Note 4" for additional information.

Related Party Transactions

Refer to "Item 8. Financial Statements and Supplementary Information—Note 4" for information about our related party transactions.

Certain Relationships

From time to time, we may do business with other companies affiliated with TPG or Goldman Sachs, which are the owners of Enfield, the beneficial owner ofour Series B Preferred Units, or with NGP, Marathon Petroleum Corporation, or Kinder Morgan, Inc., our joint venture partners in the Delaware Basin JV, Ascension 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, from and against any and all losses, claims, damages, liabilities, judgments, fines, taxes (including ERISA excise taxes), penalties (whether civil, criminal, or other), interest, assessments, amounts paid or payable in settlements, or other amounts (collectively, "losses") and expenses (as defined in the Indemnification Agreements) arising from any and all threatened, pending, or completed claims, demands, actions, suits, proceedings, or alternative dispute mechanisms, whether civil, criminal, administrative, arbitrative, investigative, or other, whether made pursuant to federal, state, or local law, whether formal or informal, and including appeals (a "proceeding"), in which the Indemnitee may be involved, or is threatened to be involved, as a party, a witness, or otherwise, including any inquiries, hearings, or investigations that the Indemnitee determines might lead to the institution of any proceeding, related to the fact that Indemnitee is or was a director, manager, or officer of us, the general partner, or the managing member of ENLC or is or was serving at the request of us, the general partner, or the managing member of ENLC as a manager, managing member, general partner, director, officer, fiduciary, trustee, or agent of any other entity, organization, or person of any nature, including service with respect to employee benefit plans, or by reason of an action or inaction by Indemnitee in any such capacity on behalf of, for the benefit of, or at the request of us, the general partner, or the managing member of ENLC. 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

Our policies and procedures for the review, approval, or ratification of transactions with "related persons" are contained in our Code of Business Conduct and Ethics (the "Code of Ethics") as well as our partnership agreement. Pursuant to our Code of Ethics, the Audit Committee of theManager Board must approve any transaction, arrangement, or relationship, or any series of similar transactions, arrangements, or relationships, in which ENLK or any of its subsidiaries is or will be a participant, the aggregate amount involved will or may be expected to exceed $120,000 in any fiscal year, and any director, executive officer, equity holder owning more than 5% of any class of ENLK's securities, or any immediate family member of any of the foregoing has or will have a direct or indirect interest.

Whenever a conflict arises between the general partner of ENLK or its affiliates, on the one hand, and ENLK and certain of its affiliates, on the other hand, the general partner of ENLK will resolve that conflict in accordance with the provisions of our partnership agreement. The general partner is authorized but not required in connection with its resolution of such conflict of interest to seek approval of a majority of the members of the Conflicts Committee of the Board, if such a committee has been formed. Any conflict of interest and any resolution of such conflict of interest will be conclusively deemed fair and reasonable to ENLK if such conflict of interest or resolution is (i) approved by a majority of the members of the Conflicts Committee (as long as the material facts known to the general partner or any of its affiliates regarding any proposed transaction were disclosed to the Conflicts Committee at the time it gave its approval), (ii) on terms no less favorable to ENLK than those generally being provided to or available from unrelated third parties, or (iii) fair to ENLK, taking into account the totality of the relationships between the parties involved (including other transactions that may be particularly favorable or advantageous to ENLK).

Director Independence

Following the Merger, we do not have securities listed on the NYSE or any other national securities exchange and are no longer subject to the rules of the NYSE, including rules that require independent directors on the Board. As a result, as of immediately following the Merger, we do not have any independent directors on the Board. 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 endedDecember 31, 2019, 2018, and 2017, review of our internal control procedures for the fiscal years ended December 31, 2019, 2018, and 2017, 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 $2.6 million, $1.8 million, and $1.7 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, 2019, 2018, and 2017 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, 2019, 2018, and 2017, except for certain tax related services in the amounts of $16.7 thousand and $17.5 thousand for the years ended December 31, 2019 and 2018, respectively, for the preparation of calculations under Internal Revenue Code Section 280G, Golden Parachute Payments, in connection with Mr. Garberding's departure from his position as President and Chief Executive Officer in August 2019 and Mr. Hummel's departure from his position as Executive Vice President / Business Unit President in August 2018.

All Other Fees

KPMG did not render services to us, other than those services covered in the section captioned "Audit Fees" and "Tax Fees" for the fiscal years ended December 31, 2019, 2018, and 2017.

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 applicable audit committee. The Chairman of the Manager Audit Committee is authorized by the Manager Audit Committee to pre-approve additional KPMG audit and non-audit services between meetings of the Manager Audit Committee, provided that the additional services do not affect KPMG's independence under applicable Commission rules and any such pre-approval is reported to the Manager Audit Committee at its next meeting. For the years ended December 31, 2019 and 2018, the Manager Audit Committee of the Board pre-approved KPMG providing certain tax related services in the amounts of $16.7 thousand and $17.5 thousand, respectively for the preparation of calculations under Internal Revenue Code Section 280G, Golden Parachute Payments, in connection with Mr. Garberding's departure from his position as President and Chief Executive Officer in August 2019 and Mr. Hummel's departure from his position as Executive Vice President / Business Unit President in August 2018.

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 **	—	Agreement and Plan of Merger, dated as of October 21, 2018, by and among EnLink Midstream, LLC, EnLink Midstream Manager, LLC, NOLA Merger Sub, LLC, EnLink Midstream Partners, LP, and EnLink Midstream GP, LLC (incorporated by reference to Exhibit 2.1 to our Current Report on Form 8-K dated October 21, 2018, filed with the Commission on October 22, 2018, 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	—	Tenth Amended and Restated Agreement of Limited Partnership of EnLink Midstream Partners, LP, dated as of January 25, 2019 (incorporated by reference to Exhibit 3.1 to our Current Report on Form 8-K dated January 25, 2019, filed with the Commission on January 29, 2019, file No. 001-36340).
3.6	—	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).
3.7	—	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).
3.8	—	Fourth Amended and Restated Limited Liability Company Agreement of EnLink Midstream GP, LLC, dated as of July 18, 2018 (incorporated by reference to Exhibit 3.1 to our Current Report on Form 8-K dated July 17, 2018, filed with the Commission on July 23, 2018, 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	—	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).
4.3	—	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).
4.4	—	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).
4.5	—	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).

4.6		—	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).
4.7		—	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, file No. 001-36340).
4.8		—	Indenture, dated as of April 9, 2019, by and between EnLink Midstream, LLC and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.1 to our Current Report on Form 8-K dated April 4, 2019, filed with the Commission on April 9, 2019, file No. 001-36340).
4.9		—	First Supplemental Indenture, dated as of April 9, 2019, by and among EnLink Midstream, LLC, 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 April 4, 2019, filed with the Commission on April 9, 2019, file No. 001-36340).
4.10	*	—	Description of Securities.
10.1		—	Form of Indemnification Agreement (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K dated July 17, 2018, filed with the Commission on July 23, 2018, file No. 001-36340).
10.2	†	—	EnLink Midstream GP, LLC Long-Term Incentive Plan, as amended and restated January 25, 2019 (the “GP Plan”) (incorporated by reference to Exhibit 4.2 to EnLink Midstream, LLC’s Registration Statement on Form S-8 dated January 28, 2019, filed with the Commission on January 28, 2019, file No. 333-229393).
10.3	†	—	EnLink Midstream, LLC 2014 Long-Term Incentive Plan, as amended and restated January 25, 2019 (the “2014 Plan”) (incorporated by reference to Exhibit 4.1 to EnLink Midstream, LLC’s Registration Statement on Form S-8 dated January 28, 2019, filed with the Commission on January 28, 2019, file No. 333-229393).
10.4	†	—	Form of Amended Performance Conditions for Certain Performance Unit Agreements made under the GP Plan and 2014 Plan, effective as of January 25, 2019 (incorporated by reference to Exhibit 10.5 to our Annual Report on Form 10-K dated December 31, 2018, filed with the Commission on February 20, 2019, file No. 001-36340).
10.5		—	Revolving Credit Agreement, dated as of December 11, 2018, by and among EnLink Midstream, LLC, Bank of America, N.A., as Administrative Agent, Swing Line Lender and L/C Issuer, Bank of Montreal and Royal Bank of Canada, as Co-Syndication Agents, Citibank, N.A. and Wells Fargo Bank, National Association, as Co-Documentation Agents, and the lenders party thereto (incorporated by reference to Exhibit 10.1 to EnLink Midstream, LLC’s Current Report on Form 8-K dated December 11, 2018, filed with the Commission on December 12, 2018, file No. 001-36336).
10.6		—	Term Loan Agreement, dated as of December 11, 2018, by and among EnLink Midstream Partners, LP, Bank of America, N.A., as Administrative Agent, Bank of Montreal and Royal Bank of Canada, as Co-Syndication Agents, Citibank, N.A. and Wells Fargo Bank, National Association, as Co-Documentation Agents, and the lenders party thereto (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K dated December 11, 2018, filed with the Commission on December 12, 2018, file No. 001-36340).
10.7		—	Guaranty Agreement, dated as of January 25, 2019, by EnLink Midstream Partners, LP in favor of Bank of America, N.A., as Administrative Agent, for the ratable benefit of the lenders from time to time party to the Revolving Credit Agreement, dated as of December 11, 2018 (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K dated January 25, 2019, filed with the Commission on January 29, 2019, file No. 001-36340).
10.8		—	New Borrower Joinder and Assumption Agreement, dated January 25, 2019, by EnLink Midstream, LLC and EnLink Midstream Partners, LP in favor of Bank of America, N.A., as Administrative Agent, and the lenders from time to time party to the Term Loan Agreement, dated as of December 11, 2018 (incorporated by reference to Exhibit 10.2 to our Current Report on Form 8-K dated January 25, 2019, filed with the Commission on January 29, 2019, file No. 001-36340).
10.9		—	Guaranty Agreement, dated as of January 25, 2019, by EnLink Midstream Partners, LP in favor of Bank of America, N.A., as Administrative Agent, for the ratable benefit of the lenders from time to time party to the Term Loan Agreement, dated as of December 11, 2018 (incorporated by reference to Exhibit 10.3 to our Current Report on Form 8-K dated January 25, 2019, filed with the Commission on January 29, 2019, file No. 001-36340).
10.10	†	—	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).

10.11	†	—	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).
10.12	†	—	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).
10.13	†	—	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).
10.14	†	—	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).
10.15	†	—	Form of Performance Unit Agreement made under the 2014 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).
10.16	†	—	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).
10.17	†	—	Form of Restricted Incentive Unit Agreement made under the 2014 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).
10.18	†	—	Form of Performance Unit Agreement made under the 2014 Plan (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K dated March 8, 2019, filed with the Commission March 14, 2019, file No. 001-36340).
10.19	†	—	Form of Restricted Incentive Unit Agreement made under the 2014 Plan (incorporated by reference to Exhibit 10.2 to our Current Report on Form 8-K dated March 8, 2019, filed with the Commission March 14, 2019, file No. 001-36340).
10.20	†	—	Form of EnLink Midstream Operating, LP Amended and Restated Severance Agreement (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K dated September 18, 2019, filed with the Commission on September 23, 2019, file No. 001-36340).
10.21	†	—	Form of EnLink Midstream Operating, LP Amended and Restated Change in Control Agreement (incorporated by reference to Exhibit 10.2 to our Current Report on Form 8-K dated September 18, 2019, filed with the Commission on September 23, 2019, file No. 001-36340).
10.22	†	—	Preferred Restructuring Agreement, dated as of October 21, 2018, by and among Enfield Holdings, L.P., TPG VII Management, LLC, WSEP Egypt Holdings, LP, WSIP Egypt Holdings, LP, EnLink Midstream, LLC, EnLink Midstream Manager, LLC, EnLink Midstream Partners, LP, and EnLink Midstream GP, LLC (incorporated by reference to Exhibit 10.4 to our Current Report on Form 8-K dated October 21, 2018, filed with the Commission on October 22, 2018, file No. 001-36340).
10.23		—	Contribution Agreement, dated as of January 31, 2019, by and between EnLink Midstream, LLC and EnLink Midstream Partners, LP (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K dated January 31, 2019, filed with the Commission on February 4, 2019, file No. 001-36340).
21.1	*	—	List of Subsidiaries.
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, 2019, formatted in iXBRL (Inline eXtensible Business Reporting Language): (i) Consolidated Balance Sheets as of December 31, 2019 and December 31, 2018, (ii) Consolidated Statements of Operations for the years ended December 31, 2019, 2018, and 2017, (iii) Consolidated Statements of Changes in Members' Equity for the years ended December 31, 2019, 2018, and 2017, (iv) Consolidated Statements of Cash Flows for the years ended December 31, 2019, 2018, and 2017, and (v) the notes to Consolidated Financial Statements.
104	*	—	Cover Page Interactive Data File (formatted as Inline iXBRL and included in Exhibit 101).

* Filed herewith.

** In accordance with the instruction on Item 601(b)(2) of Regulation S-K, the exhibits and schedules to Exhibits 2.1, 2.2, and 2.3 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.

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 26, 2020

By: /s/ BARRY E. DAVIS

Barry E. Davis

Chairman 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,and on the dates indicated.

Signature	Title	Date
/s/ BARRY E. DAVIS Barry E. Davis	Chairman, Chief Executive Officer, and Director (Principal Executive Officer)	February 26, 2020
/s/ ALAINA K. BROOKS Alaina K. Brooks	Executive Vice President, Chief Legal and Administrative Officer, Secretary, and Director	February 26, 2020
/s/ ERIC D. BATCHELDER Eric D. Batchelder	Executive Vice President and Chief Financial Officer (Principal Financial and Accounting Officer)	February 26, 2020

Exhibit 4.10

ENLINK MIDSTREAM PARTNERS, LP
DESCRIPTION OF SECURITIES

As of December 31, 2019, EnLink Midstream Partners, LP ("*we*" or "*EnLink Midstream*") had seven classes of securities registered under Section 12 of the Securities Exchange Act of 1934, as amended (the "*Exchange Act*"): (i) 4.40% senior unsecured notes due 2024 (the "*2024 Notes*"), (ii) 4.15% senior unsecured notes due 2025 (the "*2025 Notes*"), (iii) 4.85% senior unsecured notes due 2026 (the "*2026 Notes*"), (iv) 5.60% senior unsecured notes due 2044 (the "*2044 Notes*"), (v) 5.05% senior unsecured notes due 2045 (the "*2045 Notes*"), (vi) 5.45% senior unsecured notes due 2047 (the "*2047 Notes*" and together with the 2024 Notes, the 2025 Notes, the 2026 Notes, the 2044 Notes, and the 2045 Notes, the "*notes*"), and (vii) Series C Fixed-to-Floating Rate Cumulative Redeemable Perpetual Preferred Units representing limited partner interests of ENLK (the "*Series C Preferred Units*"). In addition, we are a guarantor of EnLink Midstream, LLC's ("*ENLC*") 5.375% senior notes due 2029, a description of which is incorporated herein by reference to Exhibit 4.13 to the Annual Report on Form 10-K of ENLC for the fiscal year ended December 31, 2019.

DESCRIPTION OF NOTES

We are party to a base indenture, dated March 19, 2014, between us and Wells Fargo Bank, National Association, as trustee, pursuant to which we issued the notes, as supplemented by supplemental indentures setting forth the specific terms of the series of notes. In this description, when we refer to the "indenture," we mean such base indenture as so amended and supplemented by the applicable supplemental indenture. This description is a summary of the material provisions of the notes and the indenture. This description does not restate those agreements and instruments in their entirety. You should refer to the notes and the indenture, forms of which are available as set forth below under "Available Information," for a complete description of our obligations and the rights of note holders.

You can find the definitions of various terms used in this description under "—Certain Definitions" below. In this description, the terms "EnLink Midstream," "we," "us" and "our" refer only to EnLink Midstream Partners, LP and not to any of its Subsidiaries.

General

The notes:

- are general unsecured, senior obligations of EnLink Midstream, ranking equally with all other existing and future unsecured and unsubordinated indebtedness of EnLink Midstream;
- were issued in an aggregate principal amount of $550.0 million, with respect to the 2024 Notes; an aggregate principal amount of $750.0 million, with respect to the 2025 Notes; an aggregate principal amount of $500.0 million, with respect to the 2026 Notes; an aggregate principal amount of $350.0 million, with respect to the 2044 Notes; an aggregate principal amount of $450.0 million, with respect to the 2045 Notes; and an aggregate principal amount of $500.0 million, with respect to the 2047 Notes;
- will mature on April 1, 2024, with respect to the 2024 Notes; on June 1, 2025, with respect to the 2025 Notes; on July 15, 2026, with respect to the 2026 Notes; on April 1, 2044, with respect to the 2044 Notes; on April 1, 2045, with respect to the 2045 Notes; and on June 1, with respect to the 2047 Notes;
- were issued in denominations of $2,000 and integral multiples of $1,000 in excess thereof;
- bear interest at an annual rate of 4.400%, with respect to the 2024 Notes; an annual rate of 4.150%, with respect to the 2025 Notes; an annual rate of 4.850%, with respect to the 2026 Notes; an annual rate of 5.600%, with respect to the 2044 Notes; an annual rate of 5.050%, with respect to the 2045 Notes; and an annual rate of 5.450%, with respect to the 2047 Notes.
- are redeemable at any time at our option at the redemption prices described below under "—Optional Redemption."

Each series of notes constitutes a separate series of debt securities under the indenture. The indenture does not limit the amount of debt securities we may issue under the indenture from time to time in one or more series. We may in the future issue additional debt securities under the indenture in addition to the notes as described below under "—Further Issuances."

Interest

2024 Notes

We pay interest on the 2024 Notes in cash semi-annually in arrears on April 1 and October 1 of each year. We make interest payments on the 2024 Notes to the persons in whose names the 2024 Notes are registered at the close of business on March 15 or September 15, as applicable, before the next interest payment date.

2025 Notes

We pay interest on the 2025 Notes in cash semi-annually in arrears on June 1 and December 1 of each year. We make interest payments on the 2025 Notes to the persons in whose names the 2025 Notes are registered at the close of business on May 15 or November 15, as applicable, before the next interest payment date.

2026 Notes

We pay interest on the 2026 Notes in cash semi-annually in arrears on January 15 and July 15 of each year. We make interest payments on the 2026 Notes to the persons in whose names the 2026 Notes are registered at the close of business on January 1 or July 1, as applicable, before the next interest payment date.

2044 Notes

We pay interest on the 2044 Notes in cash semi-annually in arrears on April 1 and October 1 of each year. We make interest payments on the 2044 Notes to the persons in whose names the 2044 Notes are registered at the close of business on March 15 or September 15, as applicable, before the next interest payment date.

2045 Notes

We pay interest on the 2045 Notes in cash semi-annually in arrears on April 1 and October 1 of each year. We make interest payments on the 2045 Notes to the persons in whose names the 2045 Notes are registered at the close of business on March 15 or September 15, as applicable, before the next interest payment date.

2047 Notes

We pay interest on the 2047 Notes in cash semi-annually in arrears on June 1 and December 1 of each year, beginning December 1, 2017. We make interest payments on the 2047 Notes to the persons in whose names the 2047 Notes are registered at the close of business on May 15 and November 15, as applicable, before the next interest payment date.

Computation of Interest

Interest on the notes will be computed on the basis of a 360-day year consisting of twelve 30-day months. If any interest payment date falls on a day that is not a business day, the payment will be made on the next business day, and no interest will accrue on the amount of interest due on that interest payment date for the period from and after the interest payment date to the date of payment.

Paying Agent and Registrar

The trustee acts as paying agent and registrar for the notes. We may change the paying agent or registrar without prior notice to the holders of the notes, and we or any of our Subsidiaries may act as paying agent or registrar; provided, however, that we are required to maintain at all times an office or agency in The City of New York (which may be an office of the trustee or an affiliate of the trustee or the registrar or a co-registrar for the notes) where the notes may be presented for payment and where notes may be surrendered for registration of transfer or for exchange and where notices and demands to or upon us in respect of the notes and the indenture may be served. We may also from time to time designate one or more additional offices or agencies where the notes may be presented or surrendered for any or all such purposes and may from time to time rescind such designations.

Further Issuances

We may from time to time, without notice to or the consent of the holders of the notes, create and issue additional notes having the same terms as any of the series of notes, except for issue date, issue price, and in some cases, the first interest payment date. Additional notes issued in this manner will form a single series with the previously issued and outstanding notes of such series.

Optional Redemption

2024 Notes

Prior to January 1, 2024 (three months prior to the maturity date of the 2024 Notes), the 2024 Notes are redeemable, at our option, at any time in whole, or from time to time in part, at a price equal to the greater of:

- 100% of the principal amount of the notes to be redeemed;
  or
- the sum of the present values of the remaining scheduled payments of principal and interest on the 2024 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 25 basis points, with respect to the 2024 Notes;

plus, in either case, accrued and unpaid interest to, but excluding, the redemption date.

At any time on or after January 1, 2024 (three months prior to their maturity date), the 2024 Notes will be redeemable in whole or in part, at our option, at a redemption price equal to 100% of the principal amount of the 2024 Notes to be redeemed plus accrued and unpaid interest thereon to, but excluding, the redemption date.

For purposes of determining the redemption price of the 2024 Notes, the following definitions are applicable:

"*Comparable Treasury Issue*" means the United States Treasury security selected by the Quotation Agent as having a maturity comparable to the remaining term of the 2024 Notes to be redeemed that would be utilized, at the time of selection and in accordance with customary financial practice, in pricing new issues of corporate debt securities of comparable maturity to the remaining term of such 2024 Notes.

"*Reference Treasury Dealer*" means (i) each of Citigroup Global Markets Inc. and Merrill Lynch, Pierce, Fenner & Smith Incorporated and their respective successors and (ii) two other Primary Treasury Dealers selected by us.

2025 Notes

Prior to March 1, 2025 (three months prior to the maturity date of the 2025 Notes), the 2025 Notes are redeemable, at our option, at any time in whole, or from time to time in part, at a price equal to the greater of:

- 100% of the principal amount of the 2025 Notes to be redeemed;
  or
- the sum of the present values of the remaining scheduled payments of principal and interest on the 2025 Notes to be redeemed that would be due if the 2025 Notes matured on March 1, 2025 (three months prior to the maturity date of the 2025 Notes) (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 30 basis points;

plus, in either case, accrued and unpaid interest to, but excluding, the redemption date.

At any time on or after March 1, 2025 (three months prior to their maturity date), the 2025 Notes will be redeemable in whole or in part, at our option, at a redemption price equal to 100% of the principal amount of the 2025 Notes to be redeemed plus accrued and unpaid interest thereon to, but excluding, the redemption date.

For purposes of determining the redemption price of the 2025 Notes, the following definitions are applicable:

"*Comparable Treasury Issue*" means the United States Treasury security selected by the Quotation Agent as having a maturity comparable to the remaining term of the 2025 Notes to be redeemed (calculated as if the maturity date of the 2025 Notes was March 1, 2025 (three months prior to the maturity date of the 2025 Notes)) that would be utilized, at the time of selection and in accordance with customary financial practice, in pricing new issues of corporate debt securities of comparable maturity to the remaining term of such 2025 Notes (as if the maturity date of the 2025 Notes was March 1, 2025 (three months prior to the maturity date of the 2025 Notes)).

"*Reference Treasury Dealer*" means (i) each of Barclays Capital Inc., Merrill Lynch, Pierce, Fenner & Smith Incorporated and Deutsche Bank Securities Inc. and their respective successors and (ii) one other Primary Treasury Dealer selected by us.

2026 Notes

Prior to April 15, 2026 (three months prior to the maturity date of the notes), the 2026 Notes are redeemable, at our option, at any time in whole, or from time to time in part, at a price equal to the greater of:

- 100% of the principal amount of the 2026 Notes to be redeemed;
  or
- the sum of the present values of the remaining scheduled payments of principal and interest on the 2026 Notes to be redeemed that would be due if the 2026 Notes matured on April 15, 2026 (three months prior to the maturity date of the 2026 Notes) (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 50 basis points;

plus, in either case, accrued and unpaid interest to, but excluding, the redemption date.

At any time on or after April 15, 2026 (three months prior to the maturity date of the 2026 Notes), the 2026 Notes will be redeemable in whole or in part, at our option, at a redemption price equal to 100% of the principal amount of the 2026 Notes to be redeemed plus accrued and unpaid interest thereon to, but excluding, the redemption date.

For purposes of determining the redemption price of the 2026 Notes, the following definitions are applicable:

"*Comparable Treasury Issue*" means the United States Treasury security selected by the Quotation Agent as having a maturity comparable to the remaining term of the 2026 Notes to be redeemed (calculated as if the maturity date of the notes was April 15, 2026 (three months prior to the maturity date of the 2026 Bites)) that would be utilized, at the time of selection and in accordance with customary financial practice, in pricing new issues of corporate debt securities of comparable maturity to the remaining term of such 2026 Notes (calculated as if the maturity date of the 2026 Notes was April 15, 2026 (three months prior to the maturity date of the 2026 Notes)).

"*Reference Treasury Dealer*" means each of J.P. Morgan Securities LLC and Merrill Lynch, Pierce, Fenner & Smith Incorporated and their respective successors.

2044 Notes

Prior to October 1, 2043 (six months prior to maturity date of the 2044 Notes), the 2044 Notes are redeemable, at our option, at any time in whole, or from time to time in part, at a price equal to the greater of:

- 100% of the principal amount of the 2044 Notes to be redeemed;
  or
- the sum of the present values of the remaining scheduled payments of principal and interest on the 2044 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 30 basis points, with respect to the 2044 Notes,

plus, in either case, accrued and unpaid interest to, but excluding, the redemption date.

At any time on or after October 1, 2043 (six months prior to the maturity date of the 2044 Notes), the 2044 Notes will be redeemable in whole or in part, at our option, at a redemption price equal to 100% of the principal amount of the 2044 Notes to be redeemed plus accrued and unpaid interest thereon to, but excluding, the redemption date.

For purposes of determining the redemption price of the 2044 Notes, the following definitions are applicable:

"*Comparable Treasury Issue*" means the United States Treasury security selected by the Quotation Agent as having a maturity comparable to the remaining term of the 2044 Notes to be redeemed that would be utilized, at the time of selection and in accordance with customary financial practice, in pricing new issues of corporate debt securities of comparable maturity to the remaining term of such 2044 Notes.

"*Reference Treasury Dealer*" means (i) each of Citigroup Global Markets Inc. and Merrill Lynch, Pierce, Fenner & Smith Incorporated and their respective successors and (ii) two other Primary Treasury Dealers selected by us.

2045 Notes

Prior to October 1, 2044 (six months prior to the maturity date of the 2045 Notes), the 2045 Notes are redeemable, at our option, at any time in whole, or from time to time in part, at a price equal to the greater of:

- 100% of the principal amount of the 2045 Notes to be redeemed;
  or
- the sum of the present values of the remaining scheduled payments of principal and interest on the 2045 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 30 basis points;

plus, in either case, accrued and unpaid interest to, but excluding, the redemption date.

At any time on or after October 1, 2044 (six months prior to the maturity date of the 2045 Notes), the 2045 Notes will be redeemable in whole or in part, at our option, at a redemption price equal to 100% of the principal amount of the 2045 Notes to be redeemed plus accrued and unpaid interest thereon to, but excluding, the redemption date.

For purposes of determining the redemption price of the 2045 Notes, the following definitions are applicable:

"*Comparable Treasury Issue*" means the United States Treasury security selected by the Quotation Agent as having a maturity comparable to the remaining term of the 2045 Notes to be redeemed that would be utilized, at the time of selection and in accordance with customary financial practice, in pricing new issues of corporate debt securities of comparable maturity to the remaining term of such 2045 Notes.

"*Reference Treasury Dealer*" means (i) each of Morgan Stanley & Co. LLC and RBS Securities Inc. and their respective successors and (ii) two other Primary Treasury Dealers selected by us.

2047 Notes

Prior to December 1, 2046 (six months prior to the maturity date of the 2047 Notes), the 2047 Notes are redeemable, at our option, at any time in whole, or from time to time in part, at a price equal to the greater of:

- 100% of the principal amount of the 2047 Notes to be redeemed;
  or
- the sum of the present values of the remaining scheduled payments of principal and interest on the 2047 Notes to be redeemed that would be due if the 2047 Notes matured on December 1, 2046 (six months prior to the maturity date of the 2047 Notes) (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 40 basis points;

plus, in either case, accrued and unpaid interest to, but excluding, the redemption date.

At any time on or after December 1, 2046 (six months prior to the maturity date of the 2047 Notes), the 2047 Notes will be redeemable in whole or in part, at our option, at a redemption price equal to 100% of the principal amount of the 2047 Notes to be redeemed plus accrued and unpaid interest thereon to, but excluding, the redemption date.

For purposes of determining the redemption price of the 2047 Notes, the following definitions are applicable:

"*Comparable Treasury Issue*" means the United States Treasury security selected by the Quotation Agent as having a maturity comparable to the remaining term of the 2047 Notes to be redeemed (calculated as if the maturity date of the 2047 Notes was December 1, 2046 (six months prior to the maturity date of the 2047 Notes)) that would be utilized, at the time of selection and in accordance with customary financial practice, in pricing new issues of corporate debt securities of comparable maturity to the remaining term of such 2047 Notes (calculated as if the maturity date of the 2047 Notes was December 1, 2046 (six months prior to the maturity date of the 2047 Notes)).

“*Reference Treasury Dealer*” means each of Barclays Capital Inc., Credit Suisse Securities (USA) LLC and Wells Fargo Securities, LLC and their respective successors.

Applicable Terms

For purposes of determining the redemption price of the notes, the following definitions are applicable:

“*Comparable Treasury Price*” means, with respect to any redemption date for notes, (1) the average of four Reference Treasury Dealer Quotations for such redemption date after excluding the highest and lowest of all of the Reference Treasury Dealer Quotations or (2) if the Quotation Agent obtains fewer than four such Reference Treasury Dealer Quotations, the average of all such quotations.

“*Quotation Agent*” means the Reference Treasury Dealer appointed by us.

“*Primary Treasury Dealer*” means a U.S. government securities dealer in the United States.

“*Reference Treasury Dealer Quotation*” means, with respect to each Reference Treasury Dealer and any redemption date, the average, as determined by the Quotation Agent, of the bid and asked prices for the Comparable Treasury Issue (expressed in each case as a percentage of its principal amount) quoted in writing to the Quotation Agent by such Reference Treasury Dealer at 5:00 p.m., New York City time, on the third business day preceding the redemption date.

“*Treasury Rate*” means, with respect to any redemption date, the rate per year equal to the semi-annual equivalent yield to maturity of the Comparable Treasury Issue, calculated using a price for the Comparable Treasury Issue (expressed as a percentage of its principal amount) equal to the Comparable Treasury Price for such redemption date. The Treasury Rate will be calculated on the third business day preceding any redemption date.

Redemption Procedures

If fewer than all of the notes of a series are to be redeemed at any time, such notes will be selected for redemption not more than 60 days prior to the redemption date and such selection will be made by the trustee on a pro rata basis, by lot or by such other method as the trustee deems appropriate (or, in the case of notes represented by a note in global form, by such method as The Depository Trust Company (“DTC”) may require); provided, that no partial redemption of any note will occur if such redemption would reduce the principal amount of such note to less than $2,000. Notices of redemption with respect to the notes will be sent at least 30 but not more than 60 days before the redemption date to each holder of notes to be redeemed.

If any note is to be redeemed in part only, the notice of redemption that relates to such note will state the portion of the principal amount thereof to be redeemed. A new note in principal amount equal to the unredeemed portion thereof will be issued in the name of the holder thereof upon cancellation of the original note. Notes called for redemption will become due on the date fixed for redemption. Unless we default in payment of the redemption price, on and after the redemption date, interest will cease to accrue on the notes or portions of the notes called for redemption.

Ranking

The notes are unsecured, unless we are required to secure them pursuant to the limitations on liens covenant described below under “—Certain Covenants—Limitations on Liens.” The notes are also the unsubordinated obligations of EnLink Midstream and rank equally with all other existing and future unsubordinated indebtedness of EnLink Midstream. The notes will effectively rank junior to any future indebtedness of EnLink Midstream that is both secured and unsubordinated to the extent of the value of the assets securing such indebtedness, and the notes will structurally rank junior to all indebtedness and other liabilities of EnLink Midstream’s existing and future Subsidiaries.

Open Market Purchases; No Mandatory Redemption or Sinking Fund

We may at any time and from time to time repurchase notes in the open market or otherwise, in each case without any restriction under the indenture. We are not required to make any mandatory redemption or sinking fund payments with respect to the notes.

Certain Covenants

Except as set forth below, neither EnLink Midstream nor any of its Subsidiaries is restricted by the indenture from incurring any type of indebtedness or other obligation, from paying dividends or making distributions on its partnership or other equity interests or from purchasing or redeeming its partnership or other equity interests. The indenture does not require the maintenance of any financial ratios or specified levels of net worth or liquidity. In addition, the indenture does not contain any provisions that would require EnLink Midstream to repurchase or redeem or otherwise modify the terms of the notes upon a change in control or other events involving EnLink Midstream that could adversely affect the creditworthiness of EnLink Midstream.

Limitations on Liens. EnLink Midstream will not, nor will it permit any of its Principal Subsidiaries to, create, assume, incur, or suffer to exist any mortgage, lien, security interest, pledge, charge, or other encumbrance ("liens") upon any Principal Property or upon any capital stock of any Principal Subsidiary, whether owned on the date of the supplemental indenture creating the notes or thereafter acquired, to secure any Indebtedness of EnLink Midstream or any other Person (other than the notes), without in any such case making effective provisions whereby all of the outstanding notes are secured equally and ratably with, or prior to, such Indebtedness so long as such Indebtedness is so secured.

Notwithstanding the foregoing, under the indenture, EnLink Midstream may, and may permit any of its Principal Subsidiaries to, create, assume, incur, or suffer to exist without securing the notes (a) any Permitted Lien, (b) any lien upon any Principal Property or capital stock of a Principal Subsidiary to secure Indebtedness of EnLink Midstream or any other Person, provided that the aggregate principal amount of all Indebtedness then outstanding secured by such lien and all similar liens under this clause (b), together with all Attributable Indebtedness from Sale-Leaseback Transactions (excluding Sale-Leaseback Transactions permitted by clauses (1) through (4), inclusive, of the first paragraph of the restriction on sale-leasebacks covenant described below), does not exceed 15% of Consolidated Net Tangible Assets or (c) any lien upon (i) any Principal Property that was not owned by EnLink Midstream or any of its Subsidiaries on the date of the supplemental indenture creating the notes or (ii) the capital stock of any Principal Subsidiary that owns no Principal Property that was owned by EnLink Midstream or any of its Subsidiaries on the date of the supplemental indenture creating the notes, in each case owned by a Subsidiary of EnLink Midstream (an "Excluded Subsidiary") that has not granted any liens on any of its property securing Indebtedness with recourse to EnLink Midstream or any Subsidiary of EnLink Midstream other than such Excluded Subsidiary or any other Excluded Subsidiary.

Restriction on Sale-Leasebacks. EnLink Midstream will not, and will not permit any Principal Subsidiary to, engage in the sale or transfer by EnLink Midstream or any of its Principal Subsidiaries of any Principal Property to a Person (other than EnLink Midstream or a Principal Subsidiary) and the taking back by EnLink Midstream or any Principal Subsidiary, as the case may be, of a lease of such Principal Property (a "Sale-Leaseback Transaction"), unless:

(1) such Sale-Leaseback Transaction occurs within one year from the date of completion of the acquisition of the Principal Property subject thereto or the date of the completion of construction, development or substantial repair or improvement, or commencement of full operations on such Principal Property, whichever is later;
(2) the Sale-Leaseback Transaction involves a lease for a period, including renewals, of not more than three years;
(3) EnLink Midstream or such Principal Subsidiary would be entitled to incur Indebtedness secured by a lien on the Principal Property subject thereto in a principal amount equal to or exceeding the Attributable Indebtedness from such Sale-Leaseback Transaction without equally and ratably securing the notes; or
(4) EnLink Midstream or such Principal Subsidiary, within a one-year period after such Sale-Leaseback Transaction, applies or causes to be applied an amount not less than the Attributable Indebtedness from such Sale-Leaseback Transaction to (a) the prepayment, repayment, redemption, reduction, or retirement of any Indebtedness of EnLink Midstream or any of its Subsidiaries that is not subordinated to the notes or any guarantee, or (b) the expenditure or expenditures for Principal Property used or to be used in the ordinary course of business of EnLink Midstream or its Subsidiaries.

Notwithstanding the foregoing, EnLink Midstream may, and may permit any Principal Subsidiary to, effect any Sale-Leaseback Transaction that is not excepted by clauses (1) through (4), inclusive, of the preceding paragraph provided that the Attributable Indebtedness from such Sale-Leaseback Transaction, together with the aggregate principal amount of outstanding Indebtedness (other than the notes) secured by liens other than Permitted Liens upon Principal Properties, does not exceed 15% of Consolidated Net Tangible Assets.

Merger, Consolidation or Sale of Assets. EnLink Midstream shall not consolidate with or merge into any Person or sell, lease, convey, transfer, or otherwise dispose of all or substantially all of its assets to any Person unless:

(1) the Person formed by or resulting from any such consolidation or merger or to which such assets have been transferred (the “successor”) is EnLink Midstream or expressly assumes by supplemental indenture all of EnLink Midstream’s obligations and liabilities under the indenture and the notes;
(2) the successor is organized under the laws of the United States, any state or the District of Columbia;
(3) immediately after giving effect to the transaction no Default (as defined in the indenture) or Event of Default (as defined in the indenture) has occurred and is continuing; and
(4) EnLink Midstream has delivered to the trustee an officers’ certificate and an opinion of counsel, each stating that such consolidation, merger, or transfer complies with the indenture.

The successor will be substituted for EnLink Midstream in the indenture with the same effect as if it had been an original party to the indenture. Thereafter, the successor may exercise the rights and powers of EnLink Midstream under the indenture. If EnLink Midstream conveys or transfers all or substantially all of its assets, it will be released from all liabilities and obligations under the indenture and under the notes except that no such release will occur in the case of a lease of all or substantially all of its assets.

Satisfaction and Discharge

The indenture will be discharged and will cease to be of further effect as to all notes of any series issued thereunder, when:

- either:
  - all outstanding notes of that series that have been authenticated (except lost, stolen or destroyed notes that have been replaced or paid and notes for whose payment money has theretofore been deposited in trust and thereafter repaid to us) have been delivered to the trustee for cancellation; or
  - all outstanding notes of that series that have not been delivered to the trustee for cancellation have become due and payable or will become due and payable at their stated maturity within one year or are to be called for redemption within one year under arrangements satisfactory to the trustee and in any case we have irrevocably deposited with the trustee as trust funds cash, certain U.S. government obligations or a combination thereof, in such amounts as will be sufficient, to pay the entire indebtedness of such notes not delivered to the trustee for cancellation, for principal, premium, if any, and accrued interest to the stated maturity or redemption date;
- we have paid or caused to be paid all other sums payable by us under the indenture with respect to the notes of that series; and
- we have delivered to the trustee an officers’ certificate as to the sufficiency of the trust funds, without reinvestment, to pay the entire indebtedness of such notes at maturity.

Notwithstanding such satisfaction and discharge, our obligations to compensate and indemnify the trustee, to pay additional amounts, if any, in respect of notes in certain circumstances, and to transfer or exchange debt securities pursuant to the terms thereof and our obligations and the obligations of the trustee to hold funds in trust and to apply such funds pursuant to the terms of the indenture, with respect to issuing temporary notes, with respect to the registration, transfer and exchange of notes, with respect to the replacement of mutilated, destroyed, lost or stolen notes and with respect to the maintenance of an office or agency for payment, shall in each case survive such satisfaction and discharge.

Defeasance

At any time, we may terminate, with respect to notes of a particular series, all our obligations under such series of notes and the indenture, which we call a “legal defeasance.” If we decide to make a legal defeasance, however, we may not terminate our obligations specified in the indenture, including those:

- relating to the defeasance trust;
- to register the transfer or exchange of the notes;
- to replace mutilated, destroyed, lost, or stolen notes; or
- to maintain a registrar and paying agent in respect of the notes.

At any time we may also effect a “covenant defeasance,” which means we have elected to terminate our obligations under the additional covenants established pursuant to the terms of a particular series of notes, which covenants are described in the prospectus supplement applicable to such series, and any Event of Default resulting from a failure to observe such covenants.

The legal defeasance option may be exercised notwithstanding a prior exercise of the covenant defeasance option. If the legal defeasance option is exercised, payment of the affected series of notes may not be accelerated because of an Event of Default with respect to that series. If the covenant defeasance option is exercised, payment of the affected series of debt securities may not be accelerated because of:

- the failure by us to comply for 60 days after notice with the other agreements contained in the indenture, any supplement to the indenture with respect to that series or any board resolution authorizing the issuance of that series;
- certain events of bankruptcy, insolvency, or reorganization of us; or
- an Event of Default that is added specifically for such series and described in a prospectus supplement.

In order to exercise either defeasance option, we must:

- irrevocably deposit in trust with the trustee money or certain U.S. government obligations for the payment of principal, premium, if any, and interest on the series of debt securities to redemption or stated maturity, as the case may be;
- comply with certain other conditions, including that no bankruptcy or default with respect to us has occurred and is continuing 91 days after the deposit in trust; and
- deliver to the trustee an opinion of counsel to the effect that holders of the defeased series of debt securities will not recognize income, gain or loss for Federal income tax purposes as a result of such defeasance and will be subject to Federal income tax on the same amounts and in the same manner and at the same times as would have been the case if such defeasance had not occurred. In the case of legal defeasance only, such opinion of counsel must be based on a ruling of the Internal Revenue Service or a change in applicable Federal income tax law.

Concerning the Trustee

The indenture contains certain limitations on the right of the trustee, should it become our creditor, to obtain payment of claims in certain cases, or to realize for its own account on certain property received in respect of any such claim as security or otherwise. The trustee is permitted to engage in certain other transactions. However, if it acquires any conflicting interest within the meaning of the Trust Indenture Act after a default has occurred and is continuing, it must eliminate the conflict within 90 days, apply to the SEC for permission to continue as trustee or resign.

If an Event of Default occurs and is not cured or waived, the trustee is required to exercise such of the rights and powers vested in it by the indenture and use the same degree of care and skill in their exercise as a prudent man would exercise or use under the circumstances in the conduct of his own affairs. Subject to such provisions, the trustee will not be under any obligation to exercise any of its rights or powers under the indenture at the request of any of the holders of notes unless they have offered to the trustee reasonable security or indemnity against the costs, expenses and liabilities it may incur.

Wells Fargo Bank, National Association is the trustee under the indenture and the registrar and paying agent with regard to the notes. The trustee and its affiliates maintain commercial banking and other relationships with EnLink Midstream.

Governing Law

The indenture and the notes are governed by, and construed in accordance with, the laws of the State of New York.

Book-Entry System

We have obtained the information in this section concerning The Depository Trust Company ("DTC") and its book-entry systems and procedures from DTC, and we take no responsibility for the accuracy of this information. In addition, the description in this section reflects our understanding of the rules and procedures of DTC as they are currently in effect. DTC could change its rules and procedures at any time.

Each series of notes is represented by one or more fully registered global notes. Each such global note is deposited with, or on behalf of, DTC or any successor thereto and registered in the name of Cede & Co. (DTC's nominee). Interests in the global notes may be held through DTC either as a participant in DTC or indirectly through organizations that are participants in DTC.

So long as DTC or its nominee is the registered owner of the global securities representing the notes, DTC or such nominee is considered the sole owner and holder of the notes for all purposes of the notes and the indenture. Except as provided below, owners of beneficial interests in the notes are not entitled to have the notes registered in their names, do not receive or are not entitled to receive physical delivery of the notes in definitive form and are not considered the owners or holders of the notes under the indenture, including for purposes of receiving any reports delivered by us or the trustee pursuant to the indenture.

Accordingly, each person owning a beneficial interest in a note must rely on the procedures of DTC or its nominee and, if such person is not a participant, on the procedures of the participant through which such person owns its interest, in order to exercise any rights of a holder of notes.

The Depository Trust Company. DTC acts as securities depositary for the notes. The notes are issued as fully registered notes registered in the name of Cede & Co. DTC has advised us as follows:

DTC is:

- a limited-purpose trust company organized under the New York Banking Law;
- a "banking organization" within the meaning of the New York Banking Law;
- a member of the Federal Reserve System;
- a "clearing corporation" within the meaning of the New York Uniform Commercial Code; and
- a "clearing agency" registered pursuant to the provisions of Section 17A of the Exchange Act.

DTC holds securities that its direct participants deposit with DTC. DTC facilitates the settlement among direct participants of securities transactions, such as transfers and pledges, in deposited securities through electronic computerized book-entry changes in direct participants' accounts, thereby eliminating the need for physical movement of securities certificates.

Direct participants of DTC include securities brokers and dealers (including the underwriters), banks, trust companies, clearing corporations, and certain other organizations. DTC is owned by a number of its direct participants. Access to the DTC system is also available to securities brokers and dealers, banks, and trust companies that clear through or maintain a custodial relationship with a direct participant, either directly or indirectly.

Only direct participants or indirect participants may purchase, sell or otherwise transfer ownership of, or other interests in, notes. DTC agrees with and represents to DTC participants that it will administer its book-entry system in accordance with its rules and by-laws and requirements of law. The SEC has on file a set of the rules applicable to DTC and its direct participants.

Purchases of notes under DTC's system must be made by or through direct participants, who will receive a credit for the notes on DTC's records. The ownership interest of each beneficial owner is in turn to be recorded on the records of direct participants and indirect participants. Beneficial owners will not receive written confirmation from DTC of their purchase, but beneficial owners are expected to receive written confirmations providing details of the transaction, as well as periodic statements of their holdings, from the direct participants or indirect participants through which such beneficial owners entered into the transaction. Transfers of ownership interests in the notes are to be accomplished by entries made on the books of participants acting on behalf of beneficial owners. Beneficial owners will not receive certificates representing their ownership interests in the notes, except in the event that use of the book-entry system for the notes is discontinued.

To facilitate subsequent transfers, all notes deposited by direct participants with DTC are registered in the name of DTC's nominee, Cede & Co., or such other name as may be requested by an authorized representative of DTC. The deposit of notes with DTC and their registration in the name of Cede & Co. do not effect any change in beneficial ownership. DTC has no knowledge of the actual beneficial owners of the notes. DTC's records reflect only the identity of the direct participants to whose accounts such notes are credited, which may or may not be the beneficial owners. The participants remain responsible for keeping account of their holdings on behalf of their customers.

Conveyance of notices and other communications by DTC to direct participants, by direct participants to indirect participants and by direct participants and indirect participants to beneficial owners is governed by arrangements among them, subject to any statutory or regulatory requirements as may be in effect from time to time.

Book-Entry Format. Under the book-entry format, the trustee pays interest or principal payments to Cede & Co., as nominee of DTC. DTC forwards the payment to the direct participants, who then forward the payment to the indirect participants or to the beneficial owner. Beneficial owners may experience some delay in receiving their payments under this system. Neither EnLink Midstream, the trustee under the indenture nor any paying agent has any direct responsibility or liability for the payment of principal or interest on the notes to owners of beneficial interests in the notes.

DTC is required to make book-entry transfers on behalf of its direct participants and is required to receive and transmit payments of principal, premium, if any, and interest on the notes. Any direct participant or indirect participant with which a beneficial owner of notes has an account is similarly required to make book-entry transfers and to receive and transmit payments with respect to the notes on such beneficial holder's behalf. EnLink Midstream, the underwriters and the trustee under the indenture have no responsibility for any aspect of the actions of DTC or any of its direct or indirect participants.

EnLink Midstream, the underwriters and the trustee under the indenture have no responsibility or liability for any aspect of the records kept by DTC or any of its direct or indirect participants relating to, or payments made on account of, beneficial ownership interests in the notes or for maintaining, supervising or reviewing any records relating to such beneficial ownership interests. EnLink Midstream also does not supervise these systems in any way.

The trustee will not recognize a beneficial holder of notes as a holder under the indenture, and a beneficial holder of notes can only exercise the rights of a holder indirectly through DTC and its direct participants. DTC has advised us that it will only take action regarding a note if one or more of the direct participants to whom the note is credited directs DTC to take such action and only in respect of the portion of the aggregate principal amount of the notes as to which that participant or participants has or have given that direction. DTC can only act on behalf of its direct participants. A beneficial holder of notes' ability to pledge notes to non-direct participants, and to take other actions, may be limited because the beneficial holder of notes will not possess a physical certificate that represents such notes.

Neither DTC nor Cede & Co. (nor such other DTC nominee) will consent or vote with respect to the notes unless authorized by a direct participant in accordance with DTC's procedures. Under its usual procedures, DTC will mail an omnibus proxy to EnLink Midstream as soon as possible after the record date. The omnibus proxy assigns Cede & Co.'s consenting or voting rights to those direct participants to whose accounts the notes are credited on the record date (identified in a listing attached to the omnibus proxy).

DTC has agreed to the foregoing procedures in order to facilitate transfers of the notes among its participants. However, DTC is under no obligation to perform or continue to perform those procedures, and may discontinue those procedures at any time.

Certain Definitions

"*Attributable Indebtedness*" when used with respect to any Sale-Leaseback Transaction, means, as at the time of determination, the present value (discounted at the rate set forth or implicit in the terms of the lease included in such transaction) of the total obligations of the lessee for rental payments (other than amounts required to be paid on account of property taxes, maintenance, repairs, insurance, assessments, utilities, operating, and labor costs, and other items that do not constitute payments for property rights) during the remaining term of the lease included in such Sale-Leaseback Transaction (including any period for which such lease has been extended). In the case of any lease that is terminable by the lessee upon the payment of a penalty or other termination payment, such amount shall be the lesser of the amount determined assuming termination upon the first date such lease may be terminated (in which case the amount shall also include the amount of the penalty or termination payment, but no rent shall be considered as required to be paid under such lease subsequent to the first date upon which it may be so terminated) or the amount determined assuming no such termination.

"*Consolidated Net Tangible Assets*" means, at any date of determination, the total amount of assets of EnLink Midstream and its consolidated Subsidiaries after deducting therefrom:

(1) all current liabilities (excluding (A) any current liabilities that by their terms are extendable or renewable at the option of the obligor thereon to a time more than twelve months after the time as of which the amount thereof is being computed, and (B) current maturities of long-term debt); and
(2) the value (net of any applicable reserves) of all goodwill, trade names, trademarks, patents and other like intangible assets,

all as set forth, or on a pro forma basis would be set forth, on the consolidated balance sheet of EnLink Midstream and its consolidated Subsidiaries for EnLink Midstream's most recently completed fiscal quarter for which financial statements have been filed with the SEC, prepared in accordance with generally accepted accounting principles.

"*Exchange Act*" means the Securities Exchange Act of 1934, as amended, and any successor statute.

"*General Partner*" means EnLink Midstream GP, LLC, a Delaware limited liability company, and its successors as general partner of EnLink Midstream.

"*Indebtedness*" of any Person at any date means any obligation created or assumed by such Person for the repayment of borrowed money or any guaranty thereof.

"*Permitted Liens*" means:

(1) liens upon rights-of-way for pipeline purposes;

(2) easements, rights-of-way, restrictions and other similar encumbrances affecting real property and encumbrances consisting of zoning restrictions, easements, licenses, restrictions on the use of real property or minor imperfections in title thereto and which do not in the aggregate materially adversely affect the value of the properties encumbered thereby or materially impair their use in the operation of the business of EnLink Midstream and its Subsidiaries;

(3) rights reserved to or vested by any provision of law in any municipality or public authority to control or regulate any of the properties of EnLink Midstream or any Subsidiary or the use thereof or the rights and interests of EnLink Midstream or any Subsidiary therein, in any manner under any and all laws;

(4) rights reserved to the grantors of any properties of EnLink Midstream or any Subsidiary, and the restrictions, conditions, restrictive covenants and limitations, in respect thereto, pursuant to the terms, conditions and provisions of any rights-of-way agreements, contracts or other agreements therewith;

(5) any statutory or governmental lien or lien arising by operation of law, or any mechanics', repairmen's, materialmen's, suppliers', carriers', landlords', warehousemen's or similar lien (including liens on property in the possession of storage facilities, pipelines or barges) incurred in the ordinary course of business which is not more than sixty (60) days past due or which is being contested in good faith by appropriate proceedings, if necessary, and any undetermined lien which is incidental to construction, development, improvement or repair;

(6) any right reserved to, or vested in, any municipality or public authority by the terms of any right, power, franchise, grant, license, permit or by any provision of law, to purchase or recapture or to designate a purchaser of, any property;

(7) liens for taxes and assessments which are (a) for the then current year, (b) not at the time delinquent, or (c) delinquent but the validity or amount of which is being contested at the time by EnLink Midstream or any of its Subsidiaries in good faith by appropriate proceedings;

(8) banker's liens, rights of set-off or similar rights and remedies as to deposit accounts or other funds maintained with a creditor depository institution and arising in the ordinary course of business;

(9) liens on deposits required by any Person with whom the EnLink Midstream or any Subsidiary enters into forward contracts, futures contracts, swap agreements or other commodities contracts in the ordinary course of business and in accordance with established risk management policies and liens of, or to secure performance of, leases, other than capital leases;

(10) any lien in favor of EnLink Midstream or any Subsidiary;

(11) any lien upon any property or assets of EnLink Midstream or any Subsidiary in existence on the date of the initial issuance of the notes;

(12) any lien incurred in the ordinary course of business in connection with workmen's compensation, unemployment insurance, temporary disability, social security, retiree health or similar laws or regulations or to secure obligations imposed by statute or governmental regulations or to secure letters of credit with respect thereto;

(13) liens in favor of any person to secure obligations under provisions of any letters of credit, bank guarantees, bonds or surety obligations required or requested by any governmental authority in connection with any contract or statute, provided that such obligations do not constitute Indebtedness; or any lien upon or deposits of any assets to secure performance of bids, trade contracts, leases or statutory obligations, and other obligations of a like nature incurred in the ordinary course of business or to secure letters of credit with respect thereto;

(14) any lien upon any property or assets created at the time of acquisition of such property or assets by EnLink Midstream or any of its Subsidiaries or within one year after such time to secure all or a portion of the purchase price for such property or assets or debt incurred to finance such purchase price, whether such debt was incurred prior to, at the time of or within one year after the date of such acquisition;

(15) any lien upon any property or assets to secure all or part of the cost of construction, development, repair or improvements thereon or to secure Indebtedness incurred prior to, at the time of, or within one year after completion of such construction, development, repair or improvements or the commencement of full operations thereof (whichever is later), to provide funds for any such purpose;

(16) any lien upon any property or assets existing thereon at the time of the acquisition thereof by EnLink Midstream or any of its Subsidiaries and any lien upon any property or assets of a Person existing thereon at the time such Person becomes a Subsidiary of EnLink Midstream by acquisition, merger or otherwise; provided that, in each case, such lien only encumbers the property or assets so acquired or owned by such Person at the time such Person becomes a Subsidiary and any additions thereto, proceeds thereof and property in replacement or substitution thereof;

(17) liens imposed by law or order as a result of any proceeding before any court or regulatory body that is being contested in good faith, and liens which secure a judgment or other court-ordered award or settlement as to which EnLink Midstream or the applicable Subsidiary has not exhausted its appellate rights;

(18) any extension, renewal, refinancing, refunding or replacement (or successive extensions, renewals, refinancing, refunding or replacements) of liens, in whole or in part, referred to in clauses (1) through (17) above; provided, however, that any such extension, renewal, refinancing, refunding or replacement lien shall be limited to the property or assets covered by the lien extended, renewed, refinanced, refunded or replaced and that the obligations secured by any such extension, renewal, refinancing, refunding or replacement lien shall be in an amount not greater than the amount of the obligations secured by the lien extended, renewed, refinanced, refunded or replaced and any expenses of EnLink Midstream or its Subsidiaries (including any premium) incurred in connection with such extension, renewal, refinancing, refunding or replacement; or

(19) any lien resulting from the deposit of moneys or evidence of indebtedness in trust for the purpose of defeasing Indebtedness of EnLink Midstream or any of its Subsidiaries.

"*Person*" means any individual, corporation, partnership, limited liability company, joint venture, incorporated or unincorporated association, joint-stock company, trust, unincorporated organization, government, or any agency or political subdivision thereof or any other entity.

"*Principal Property*" means, whether owned or leased on the date of the initial issuance of the notes or thereafter acquired:

(1) any pipeline assets of EnLink Midstream or any of its Subsidiaries, including any related facilities employed in the gathering, transportation, distribution, storage, or marketing of natural gas, refined petroleum products, natural gas liquids, and petrochemicals, that are located in the United States of America or any territory or political subdivision thereof; and

(2) any processing, compression, treating, blending, or manufacturing plant or terminal owned or leased by EnLink Midstream or any of its Subsidiaries that is located in the United States or any territory or political subdivision thereof, except in the case of either of the preceding clause (1) or this clause (2):

   (a) any such assets consisting of inventories, furniture, office fixtures and equipment (including data processing equipment), vehicles, and equipment used on, or useful with, vehicles; and

   (b) any such assets which, in the opinion of the board of directors of the General Partner are not material in relation to the activities of EnLink Midstream and its Subsidiaries taken as a whole.

"*Principal Subsidiary*" means any Subsidiary owning or leasing, directly or indirectly through ownership in another Subsidiary, any Principal Property.

"*Subsidiary*" means, as to any Person, (1) any corporation, association, or other business entity (other than a partnership or limited liability company) of which more than 50% of the outstanding capital stock having ordinary voting power is at the time owned or controlled, directly or indirectly, by such Person or one or more of the other Subsidiaries of such Person or (2) any general or limited partnership or limited liability company, (a) the sole general partner or member of which is the Person or a Subsidiary of the Person or (b) if there is more than one general partner or member, either (i) the only managing general partners or managing members of such partnership or limited liability company are such Person or Subsidiaries of such Person or (ii) such Person owns or controls, directly or indirectly, a majority of the outstanding general partner interests, member interests or other voting equities of such partnership or limited liability company, respectively.

DESCRIPTION OF SERIES C PREFERRED UNITS

The following description of the Series C Preferred Units does not purport to be complete and is subject to, and qualified in its entirety by reference to, the provisions of our Tenth Amended and Restated Agreement of Limited Partnership (the "Partnership Agreement"), which is filed as Exhibit 3.5 to ENLC's Annual Report on Form 10-K for the fiscal year ended December 31, 2019.

General

There are 400,000 Series C Preferred Units issued and outstanding. We may, without notice to or consent of the holders of the then-outstanding Series C Preferred Units, authorize and issue additional Series C Preferred Units and Junior Securities (as defined below) and, subject to the limitations described under "—Voting Rights," Senior Securities (as defined below) and Parity Securities (as defined below).

The holders of our common units, Series B Cumulative Convertible Preferred Units (the "Series B Preferred Units"), and Series C Preferred Units are entitled to receive, to the extent permitted by law, such distributions as may from time to time be declared by our general partner. Upon any liquidation, dissolution, or winding up of our affairs, whether voluntary or involuntary, the holders of our common units, Series B Preferred Units, and Series C Preferred Units are entitled to receive distributions of our assets, after we have satisfied or made provision for our outstanding indebtedness and other obligations and after payment to the holders of any class or series of limited partner interests (including the Series B Preferred Units and the Series C Preferred Units) having preferential rights to receive distributions of our assets.

The Series C Preferred Units are fully paid and nonassessable (except as such nonassessability may be affected by Section 17-303(a), 17-607 and 17-804 of the Delaware Revised Uniform Limited Partnership Act). Subject to the matters described under "—Liquidation Rights," each Series C Preferred Unit generally has a fixed liquidation preference of $1,000 per Series C Preferred Unit (subject to adjustment for any splits, combinations or similar adjustment to the Series C Preferred Units) plus an amount equal to accumulated and unpaid distributions thereon to, but not including, the date fixed for payment, whether or not declared.

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 such, the Series C Preferred Units rank junior to the Series B Preferred Units and to all of our current and future indebtedness and other liabilities with respect to assets available to satisfy claims against us. The rights of the holders of Series C Preferred Units to receive the liquidation preference are subject to the senior rights of the Series B Preferred Units and to the proportional rights of holders of Parity Securities.

All of the Series C Preferred Units are represented by a single certificate issued to The Depository Trust Company (and its successors or assigns or any other securities depositary selected by us) (the "Securities Depositary") and registered in the name of its nominee, for credit to an account of a direct or indirect participant in the Securities Depositary (including, if applicable, Euroclear Bank S.A./N.V., as operator of the Euroclear System ("Euroclear") and Clearstream Banking, société anonyme ("Clearstream")). So long as a Securities Depositary has been appointed and is serving, no person acquiring Series C Preferred Units will be entitled to receive a certificate representing such Series C Preferred Units unless applicable law otherwise requires or the Securities Depositary resigns or is no longer eligible to act as such and a successor is not appointed. See "—Book-Entry System."

The Series C Preferred Units are not convertible into common units or any other securities and do not have exchange rights or are not entitled or subject to any preemptive or similar rights. The Series C Preferred Units are not subject to mandatory redemption or to any sinking fund requirements. The Series C Preferred Units will be subject to redemption, in whole or in part, at our option commencing on December 15, 2022. See "—Redemption."

We have appointed American Stock Transfer & Trust Company, LLC as the paying agent (the "Paying Agent"), and the registrar and transfer agent (the "Registrar and Transfer Agent"), for the Series C Preferred Units. The address of the Paying Agent and the Registrar and Transfer Agent is 6201 15th Avenue, Brooklyn, New York, 11219.

Ranking

The Series C Preferred Units, with respect to anticipated semi-annual or quarterly distributions and distributions upon the liquidation, winding up, and dissolution of our affairs, rank:

- senior to our common units and to each other class or series of limited partner interests or other equity securities established after the original issue date of the Series C Preferred Units that is not expressly made senior to or on parity with the Series C Preferred Units as to the payment of distributions and amounts payable on a liquidation event (the "Junior Securities");
- on parity with any class or series of limited partner interests or other equity securities established after the original issue date of the Series C Preferred Units with terms expressly providing that such class or series ranks on parity with the Series C Preferred Units as to the payment of distributions and amounts payable upon a liquidation event (the "Parity Securities");
- junior to (i) our Series B Preferred Units and (ii) each other class or series of limited partner interests or equity securities established after the original issue date of the Series C Preferred Units with terms expressly made senior to the Series C Preferred Units as to the payment of distributions and amounts payable upon a liquidation event (the securities described in clauses (i) and (ii) being referred to herein as "Senior Securities"); and
- junior to all of our existing and future indebtedness and other liabilities with respect to assets available to satisfy claims against us.

Under our Partnership Agreement, we may issue Junior Securities from time to time in one or more series without the consent of the holders of the Series C Preferred Units. Our general partner has the authority to determine the designations, preferences, rights, powers, and duties of any such series before the issuance of any units of that series. Our general partner will also determine the number of units constituting each series of securities. Our ability to issue additional Parity Securities in certain circumstances or Senior Securities is limited as described under "—Voting Rights."

Liquidation Rights

Any distributions made upon our liquidation will be made to our partners in accordance with their respective positive capital account balances. The holders of outstanding Series B Preferred Units will first be specially allocated items of our gross income and gain in a manner designed to cause, in the event of any liquidation, dissolution, or winding up of our affairs (whether voluntary or involuntary), such holders to have a positive capital balance equal to the liquidation preference of $15.00 per Series B Preferred Unit. The holders of outstanding Series C Preferred Units will then be specially allocated remaining items of our gross income and gain in a manner designed to cause, in the event of any liquidation, dissolution, or winding up of our affairs (whether voluntary or involuntary), such holders to have a positive capital balance equal to the liquidation preference of $1,000 per Series C Preferred Unit (subject to adjustment for any splits, combinations or similar adjustment to the Series C Preferred Units). If the amount of our gross income and gain available to be specially allocated to the Series C Preferred Units (after any such allocation to the Series B Preferred Units) is not sufficient to cause the capital account of a Series C Preferred Unit to equal the liquidation preference of a Series C Preferred Unit, then the amount that a holder of Series C Preferred Units would receive upon liquidation may be less than the Series C Preferred Unit liquidation preference. Any accumulated and unpaid distributions on the Series C Preferred Units will be paid prior to any distributions in liquidation made in accordance with capital account balances, but after the payment of any accumulated and unpaid distributions on the Series B Preferred Units. The rights of the holders of Series C Preferred Units to receive the liquidation preference will be subject to the senior rights of the Series B Preferred Units and to the proportional rights of holders of Parity Securities.

Voting Rights

The Series C Preferred Units have no voting rights except as set forth below or as otherwise provided by Delaware law.
Unless we have received the affirmative vote or consent of the holders of at least two-thirds of the outstanding Series C Preferred Units, voting as a separate class, we may not adopt any amendment to our Partnership Agreement that has a material adverse effect on the terms of the Series C Preferred Units.

In addition, unless we have received the affirmative vote or consent of the holders of at least two-thirds of the outstanding Series C Preferred Units, voting as a class together with holders of any other Parity Securities upon which like voting rights have been conferred and are exercisable, we may not:

- create or issue any Parity Securities (including any additional Series C Preferred Units) if the cumulative distributions payable on then outstanding Series C Preferred Units (or Parity Securities, if applicable) are in arrears; or
- create or issue any Senior Securities (other than payments-in-kind on the Series B Preferred Units).

On any matter described above on which the holders of the Series C Preferred Units are entitled to vote as a class, such holders are entitled to one vote per Series C Preferred Unit. The Series C Preferred Units held by us or any of our subsidiaries or controlled affiliates are not entitled to vote.

Series C Preferred Units held in nominee or street name account will be voted by the broker or other nominee in accordance with the instruction of the beneficial owner unless the arrangement between the beneficial owner and its nominee provides otherwise.

Distributions

General

Holders of Series C Preferred Units are entitled to receive, when, as, and if declared by our general partner out of legally available funds for such purpose, cumulative cash distributions. Unless otherwise determined by our general partner, distributions on the Series C Preferred Units will be deemed to have been paid out of our available cash with respect to the quarter ended immediately preceding the quarter in which the distribution is made.

Distribution Rate

Distributions on Series C Preferred Units are cumulative from the date of original issue and are payable semi-annually in arrears (as described under "—Distribution Payment Dates") through and including December 15, 2022 and, thereafter, quarterly in arrears, when, as, and if 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 (the "Fixed Rate Period") is 6.000% per annum of the $1,000 liquidation preference per unit (equal to $60.00 per unit per annum). On and after December 15, 2022 (the "Floating Rate Period"), distributions on the Series C Preferred Units will accumulate for each distribution period at a percentage of the $1,000 liquidation preference equal to an annual floating rate of the three-month LIBOR plus a spread of 4.11%.

LIBOR for each distribution period during the Floating Rate Period ("Three-Month LIBOR Rate") will be determined by the Calculation Agent (as defined under "—Calculation Agent"), as of the applicable Determination Date (as defined below), in accordance with the following provisions:

- the rate (expressed as a percentage per year) for deposits in U.S. dollars for a three-month period commencing on the first day of such distribution period that appears on Reuters Page LIBOR01 as of 11:00 a.m., London time, on such Determination Date; or
- if no such rate is so published, we will select four major banks in the London interbank market and request that the principal London offices of those four selected banks provide their offered quotations for deposits in U.S. dollars for a period of three months, commencing on the first day of the applicable distribution period, to prime banks in the London interbank market at approximately 11:00 a.m. (London time) on the Determination Date for such distribution period. Offered quotations must be based on a principal amount equal to an amount that, in our judgment, is representative of a single transaction in U.S. dollars in the London interbank market at the time. If two or more quotations are provided, the Three-Month LIBOR Rate for such distribution period will be the arithmetic mean of the quotations. If fewer than two quotations are provided, the Three-Month LIBOR Rate for such distribution period will be the arithmetic mean of the rates quoted on the Determination Date for such distribution period by three major banks in New York City selected by us, for loans in U.S. dollars to leading European banks for a three-month period commencing on the first day of such distribution period. The rates quoted must be based on an amount that, in our judgment, is representative of a single transaction in U.S. dollars in that market at the time. If no quotation is provided as described above, the Calculation Agent, after consulting such sources as it deems comparable to any of the foregoing quotations or display page, or any such source as it deems reasonable from which to estimate the Three-Month LIBOR Rate, shall determine the Three-Month LIBOR Rate in its sole discretion.

All percentages resulting from any of the above calculations will be rounded, if necessary, to the nearest one hundred-thousandth of a percentage point, with five one-millionths of a percentage point rounded upwards (e.g., 9.876545% (or .09876545) being rounded to 9.87655% (or .0987655)) and all dollar amounts used in or resulting from such calculations will be rounded to the nearest cent (with one-half cent being rounded upwards).

"Determination Date" means the London Business Day (as defined below) immediately preceding the first date of the applicable distribution period.

"London Business Day" means any day on which dealings in deposits in U.S. dollars are transacted in the London interbank market.

"Reuters Page LIBOR01" means the display so designated on the Reuters 3000 Xtra (or such other page as may replace the LIBOR01 page on that service, or such other service as may be nominated by the British Bankers' Association for the purpose of displaying London interbank offered rates for U.S. dollar deposits).

Distribution Payment Dates

The "Distribution Payment Dates" for the Series C Preferred Units are the 15th day of June and December of each year, continuing through the end of the Fixed Rate Period and on the 15th day of March, June, September and December of each year during the Floating Rate Period. Distributions accumulate in each such period from and including the preceding Distribution Payment Date or the initial issue date, as the case may be, to but excluding the applicable Distribution Payment Date for such period, and distributions accrue on accumulated distributions at the applicable distribution rate. If any Distribution Payment Date otherwise would fall on a day that is not a Business Day, declared distributions will be paid on the immediately succeeding Business Day without the accumulation of additional distributions. During the Fixed Rate Period, distributions on the Series C Preferred Units are payable based on a 360-day year consisting of twelve 30-day months. During the Floating Rate Period, distributions on the Series C Preferred Units will be computed by multiplying the floating rate for that distribution period by a fraction, the numerator of which will be the actual number of days elapsed during that distribution period (determined by including the first day of the distribution period and excluding the last day, which is the distribution payment date), and the denominator of which will be 360, and by multiplying the result by the aggregate liquidation preference of the Series C Preferred Units. “Business Day” means Monday through Friday of each week, except that a legal holiday recognized as such by the government of the United States of America or the States of Texas or New York shall not be regarded as a Business Day.

Payment of Distributions

Not later than 5:00 p.m., New York City time, on each Distribution Payment Date, we will pay those distributions, if any, on the Series C Preferred Units that have been declared by our general partner to the holders of such Series C Preferred Units as such holders’ names appear on our unit transfer books maintained by the Registrar and Transfer Agent on the applicable record date. The record date will be the first Business Day of the month of the applicable Distribution Payment Date, except that in the case of payments of distributions in arrears, the record date with respect to a Distribution Payment Date will be such date as may be designated by our general partner in accordance with our Partnership Agreement.

So long as the Series C Preferred Units are held of record by the nominee of the Securities Depositary, declared distributions will be paid to the Securities Depositary in same-day funds on each Distribution Payment Date. The Securities Depositary will credit accounts of its participants in accordance with the Securities Depositary’s normal procedures. The participants will be responsible for holding or disbursing such payments to beneficial owners of the Series C Preferred Units in accordance with the instructions of such beneficial owners.

No distribution may be declared or paid or set apart for payment on any Junior Securities (other than a distribution payable solely in Junior Securities) unless full cumulative distributions have been or contemporaneously are being paid or provided for on all outstanding Series C Preferred Units and any Parity Securities through the most recent respective distribution payment dates. Accumulated distributions in arrears for any past distribution period may be declared by the general partner and paid on any date fixed by the general partner, whether or not a Distribution Payment Date, to holders of the Series C Preferred Units on the record date for such payment, which may not be less than 10 days before such payment date.

Subject to the next succeeding sentence, if all accumulated distributions in arrears on all outstanding Series C Preferred Units and any Parity Securities have not been declared and paid, or sufficient funds for the payment thereof have not been set apart, payment of accumulated distributions in arrears will be made in order of their respective distribution payment dates, commencing with the earliest distribution payment date. If less than all distributions payable with respect to all Series C Preferred Units and any Parity Securities are paid, any partial payment will be made pro rata with respect to the Series C Preferred Units and any Parity Securities entitled to a distribution payment at such time in proportion to the aggregate amounts remaining due in respect of such Series C Preferred Units and Parity Securities at such time. Holders of the Series C Preferred Units will not be entitled to any distribution, whether payable in cash, property or units, in excess of full cumulative distributions. Except insofar as distributions accrue on the amount of any accumulated and unpaid distributions no interest or sum of money in lieu of interest will be payable in respect of any distribution payment which may be in arrears on the Series C Preferred Units.

Redemption

Optional Redemption Upon a Rating Event

At any time within 120 days after the conclusion of any review or appeal process instituted by us following the occurrence of a Rating Event (as defined below), we may, at our option, redeem the Series C Preferred Units in whole, but not in part, at a redemption price in cash per Series C Preferred Unit equal to $1,020 (102% of the liquidation preference of $1,000) plus an amount equal to all accumulated and unpaid distributions thereon to, but not including, the date fixed for redemption, whether or not declared. Any such redemption would be effected only out of funds legally available for such purpose and would be subject to compliance with the provisions of the instruments governing our outstanding indebtedness and our Series B Preferred Units.

“Rating Event” means a change by any nationally recognized statistical rating organization (within the meaning of Section 3(a)(62) of the Exchange Act) that publishes a rating for us (a “rating agency”) to its equity credit criteria for securities such as the Series C Preferred Units, as such criteria are in effect as of the original issue date of the Series C Preferred Units (the “current criteria”), which change results in (i) any shortening of the length of time for which the current criteria are scheduled to be in effect with respect to the Series C Preferred Units, or (ii) a lower equity credit being given to the Series C Preferred Units than the equity credit that would have been assigned to the Series C Preferred Units by such rating agency pursuant to its current criteria.

Optional Redemption on or after December 15, 2022

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 thereon to, but not including, the date of redemption, whether or not declared. We may undertake multiple partial redemptions. Any such redemption would be effected only out of funds legally available for such purpose and would be subject to compliance with the provisions of the instruments governing our outstanding indebtedness and our Series B Preferred Units.

Redemption Procedures

Any optional redemption shall be effected only out of funds legally available for such purpose. We will give notice of any redemption not less than 30 days and not more than 60 days before the scheduled date of redemption, to the holders of any Series C Preferred Units to be redeemed as such holders' names appear on our unit transfer books maintained by the Registrar and Transfer Agent at the address of such holders shown therein. Such notice shall state: (i) the redemption date, (ii) the number of Series C Preferred Units to be redeemed and, if less than all outstanding Series C Preferred Units are to be redeemed, the number (and, in the case of Series C Preferred Units in certificated form, the identification) of Series C Preferred Units to be redeemed from such holder, (iii) the redemption price, (iv) the place where any Series C Preferred Units in certificated form are to be redeemed and shall be presented and surrendered for payment of the redemption price therefor, and (v) that distributions on the Series C Preferred Units to be redeemed will cease to accumulate from and after such redemption date.

If fewer than all of the outstanding Series C Preferred Units are to be redeemed, the number of Series C Preferred Units to be redeemed will be determined by us, and such Series C Preferred Units will be redeemed by such method of selection as the Securities Depositary shall determine, pro rata or by lot, with adjustments to avoid redemption of fractional units. So long as all Series C Preferred Units are held of record by the nominee of the Securities Depositary, we will give notice, or cause notice to be given, to the Securities Depositary of the number of Series C Preferred Units to be redeemed, and the Securities Depositary will determine the number of Series C Preferred Units to be redeemed from the account of each of its participants holding such Series C Preferred Units in its participant account. Thereafter, each participant will select the number of Series C Preferred Units to be redeemed from each beneficial owner for whom it acts (including the participant, to the extent it holds Series C Preferred Units for its own account). A participant may determine to redeem Series C Preferred Units from some beneficial owners (including the participant itself) without redeeming Series C Preferred Units from the accounts of other beneficial owners.

So long as the Series C Preferred Units are held of record by the nominee of the Securities Depositary, the redemption price will be paid by the Paying Agent to the Securities Depositary on the redemption date. The Securities Depositary's normal procedures provide for it to distribute the amount of the redemption price in same-day funds to its participants who, in turn, are expected to distribute such funds to the persons for whom they are acting as agent.

If we give or cause to be given a notice of redemption, then we will deposit with the Paying Agent funds sufficient to redeem the Series C Preferred Units as to which notice has been given by 10:00 a.m., New York City time, on the date fixed for redemption, and will give the Paying Agent irrevocable instructions and authority to pay the redemption price to the holder or holders thereof upon surrender or deemed surrender (which will occur automatically if the certificate representing such Series C Preferred Units is issued in the name of the Securities Depositary or its nominee) of the certificates therefor. If notice of redemption shall have been given, then from and after the date fixed for redemption, unless we default in providing funds sufficient for such redemption at the time and place specified for payment pursuant to the notice, all distributions on such Series C Preferred Units will cease to accumulate and all rights of holders of such Series C Preferred Units as limited partners will cease, except the right to receive the redemption price, including an amount equal to accumulated and unpaid distributions to the date fixed for redemption, whether or not declared. The holders of Series C Preferred Units will have no claim to the interest income, if any, earned on such funds deposited with the Paying Agent. Any funds deposited with the Paying Agent hereunder by us for any reason, including, but not limited to, redemption of Series C Preferred Units, that remain unclaimed or unpaid after one year after the applicable redemption date or other payment date, shall be, to the extent permitted by law, repaid to us upon our written request, after which repayment the holders of the Series C Preferred Units entitled to such redemption or other payment shall have recourse only to us.

If only a portion of the Series C Preferred Units represented by a certificate has been called for redemption, upon surrender of the certificate to the Paying Agent (which will occur automatically if the certificate representing such Series C Preferred Units is registered in the name of the Securities Depositary or its nominee), we will issue and the Paying Agent will deliver to the holder of such Series C Preferred Units a new certificate (or adjust the applicable book-entry account) representing the number of Series C Preferred Units represented by the surrendered certificate that have not been called for redemption.

Notwithstanding any notice of redemption, there will be no redemption of any Series C Preferred Units called for redemption until funds sufficient to pay the full redemption price of such Series C Preferred Units, including all accumulated and unpaid distributions to, but not including, the date of redemption, whether or not declared, have been deposited by us with the Paying Agent.

We may from time to time purchase Series C Preferred Units, subject to compliance with all applicable securities and other laws. We have no obligation, or any present plan or intention, to purchase any Series C Preferred Units. Any Series C Preferred Units that we redeem or otherwise acquire will be cancelled.

Notwithstanding the foregoing, in the event that full cumulative distributions on the Series C Preferred Units and any Parity Securities have not been paid or declared and set apart for payment, we may not repurchase, redeem, or otherwise acquire, in whole or in part, any Series C Preferred Units or Parity Securities except pursuant to a purchase or exchange offer made on the same relative terms to all holders of Series C Preferred Units and any Parity Securities. Common units and any other Junior Securities may not be redeemed, repurchased, or otherwise acquired by us unless full cumulative distributions on the Series C Preferred Units and any Parity Securities for all prior and the then-ending distribution periods have been paid or declared and set apart for payment.

No Sinking Fund

The Series C Preferred Units do not have the benefit of any sinking fund.

No Fiduciary Duty

We, and the officers and directors of our general partner, will not owe any duties, including fiduciary duties, to holders of the Series C Preferred Units other than an implied contractual duty of good faith and fair dealing pursuant to our Partnership Agreement.

Book-Entry System

All Series C Preferred Units are represented by a single certificate issued to the Securities Depositary, and registered in the name of its nominee (initially, Cede & Co.), for credit to an account of a direct or indirect participant in the Securities Depositary (including, if applicable, Euroclear and Clearstream). The Series C Preferred Units will continue to be represented by a single certificate registered in the name of the Securities Depositary or its nominee, and no holder of the Series C Preferred Units will be entitled to receive a certificate evidencing such Series C Preferred Units unless otherwise required by law or the Securities Depositary gives notice of its intention to resign or is no longer eligible to act as such and we have not selected a substitute Securities Depositary within 60 calendar days thereafter. Payments and communications made by us to holders of the Series C Preferred Units will be duly made by making payments to, and communicating with, the Securities Depositary. Accordingly, unless certificates are available to holders of the Series C Preferred Units, each purchaser of Series C Preferred Units must rely on (i) the procedures of the Securities Depositary and its participants (including, if applicable, Euroclear and Clearstream) to receive distributions, any redemption price, liquidation preference, and notices, and to direct the exercise of any voting or nominating rights, with respect to such Series C Preferred Units and (ii) the records of the Securities Depositary and its participants (including, if applicable, Euroclear and Clearstream) to evidence its ownership of such Series C Preferred Units.
So long as the Securities Depositary (or its nominee) is the sole holder of the Series C Preferred Units, no beneficial holder of the Series C Preferred Units will be deemed to be a holder of Series C Preferred Units. The Depository Trust Company, the initial Securities Depositary, is a New York-chartered limited purpose trust company that performs services for its participants, some of whom (and/or their representatives) own The Depository Trust Company. The Securities Depositary maintains lists of its participants and will maintain the positions (i.e., ownership interests) held by its participants in the Series C Preferred Units, whether as a holder of the Series C Preferred Units for its own account or as a nominee for another holder of the Series C Preferred Units.

Calculation Agent

Wells Fargo Bank, National Association, or any other firm appointed by us, is the “Calculation Agent” for the Series C Preferred Units.

Exhibit 21.1

List of Subsidiaries

Name of Subsidiary	State of Organization
Acacia Natural Gas, L.L.C.	Delaware
Ascension Pipeline Company, LLC	Delaware
Bridgeline Holdings, L.P.	Delaware
Cedar Cove Midstream LLC	Delaware
Coronado Midstream LLC	Texas
Delaware G&P, LLC	Delaware
Delaware Processing LLC	Delaware
EnLInk Appalachia, 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 Energy GP, LLC	Delaware
EnLink Gas Marketing, LP	Texas
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 Nominee Corp.	Delaware
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 Texas NGL Pipeline, LLC	Texas
EnLink Texas Processing, LP	Texas
EnLink Tuscaloosa, LLC	Louisiana
Gulf Coast Fractionators	Texas
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

Exhibit 31.1

CERTIFICATIONS

I, Barry E. Davis, 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 26, 2020

/s/ BARRY E. DAVIS

BARRY E. DAVIS

Chairman 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 26, 2020

/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 the Registrant for the year ended December 31, 2019 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), each of the undersigned, Barry E. Davis, Chairman and Chief Executive Officer of EnLink Midstream GP, LLC, and Eric D. Batchelder, Executive Vice President and 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 26, 2020	/s/ BARRY E. DAVIS
	Barry E. Davis
	Chairman and Chief Executive Officer
Date: February 26, 2020	/s/ ERIC D. BATCHELDER
	Eric D. Batchelder
	Executive Vice President and 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.