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, 2020

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: 001-36336

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

Delaware	**46-4108528**
(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
Common Units Representing Limited Liability Company Interests	ENLC	The New York Stock Exchange

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

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

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

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

Indicate by check mark whether the registrant has submitted electronically 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 has filed a report on and attestation to its management's assessment of the effectiveness of its internal control over financial reporting under Section 404(b) of the Sarbanes-Oxley Act (15 U.S.C. 7262(b)) by the registered public accounting firm that prepared or issued its audit report. ☒

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

The aggregate market value of the common units representing limited liability company interests held by non-affiliates of the registrant was approximately $ 646.9 million on June 30, 2020, based on $2.44 per unit, the closing price of the common units as reported on the New York Stock Exchange on such date.

At February 11, 2021, there were 490,048,405 common units outstanding.

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 Plan	ENLC's 2014 Long-Term Incentive Plan.
2017 EDA	Equity Distribution Agreement entered into by ENLK in August 2017 with 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. The 2017 EDA was terminated following the consummation of the Merger.
Adjusted gross margin	Revenue less cost of sales, exclusive of operating expenses and depreciation and amortization related to our operating segments. Adjusted gross 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 additional information.
AMZ	Alerian MLP Index for Master Limited Partnerships.
AR Facility	A three-year committed accounts receivable securitization facility of up to $250 million entered into by EnLink Midstream Funding, LLC, a bankruptcy-remote special purpose entity and our indirect subsidiary, with PNC Bank, National Association, as administrative agent and lender, and PNC Capital Markets, LLC, as structuring agent.
ASC	The FASB Accounting Standards Codification.
ASC 350	ASC 350, *Intangibles—Goodwill and Other*.
ASC 606	ASC 606, *Revenue from Contracts with Customers.*
ASC 815	ASC 815, *Derivatives and Hedging.*
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.
BLM	Bureau of Land Management.
BKV	Banpu Kalnin Ventures Corporation, an affiliate of BKV Oil and Gas Capital Partners.
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	A large sedimentary basin in West Texas and New Mexico.
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 and the Tiger plant located in the Delaware Basin in Texas.
Devon	Devon Energy Corporation.
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.
ENLC Credit Facility	A $250.0 million secured revolving credit facility entered into by ENLC that would have matured on March 7, 2019, which included a $125.0 million letter of credit subfacility. The ENLC Credit Facility was terminated on January 25, 2019 in connection with the consummation of the Merger.

ENLC EDA	Equity Distribution Agreement entered into by ENLC in February 2019 with RBC Capital Markets, LLC, Merrill Lynch, Pierce, Fenner & Smith Incorporated, Barclays Capital Inc., BMO Capital Markets Corp., Citigroup Global Markets Inc., Credit Suisse Securities (USA) LLC, J.P. Morgan Securities LLC, Jefferies LLC, Mizuho Securities USA LLC, MUFG Securities Americas Inc., SunTrust Robinson Humphrey, Inc., and Wells Fargo Securities, LLC (collectively, the “ENLC Sales Agents”) to sell up to $400.0 million in aggregate gross sales of ENLC common units from time to time through an “at the market” equity offering program.
ENLK	EnLink Midstream Partners, LP or, when applicable, EnLink Midstream Partners, LP together with its consolidated subsidiaries. Also referred to as the “Partnership.”
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.
ENLK Sales Agents	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.
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.
General Partner	EnLink Midstream GP, LLC, the general partner of ENLK, which owns a 0.4% general partner interest in ENLK. Prior to the effective time of the Merger, the General Partner also owned all of the incentive distribution rights in ENLK.
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 to GIP.
Goldman Sachs	Goldman Sachs Group, Inc.
GP Plan	The General Partner’s Long-Term Incentive Plan.
ISDAs	International Swaps and Derivatives Association Agreements.
Managing Member	EnLink Midstream Manager, LLC, the managing member of ENLC.
MEGA system	Midland Energy Gathering Area system in Midland, Martin, and Glasscock counties, Texas.
Merger	On January 25, 2019, NOLA Merger Sub, LLC (previously a wholly-owned subsidiary of ENLC) 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, ENLC, the Managing Member, and NOLA Merger Sub related to the Merger.
Midland Basin	A large sedimentary basin in West Texas.
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.
OPEC+	Organization of the Petroleum Exporting Countries and its broader partners.
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.
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 owned by the Delaware Basin JV.
TPG	TPG Global, LLC.
VEX	The Victoria Express Pipeline and related truck terminal and storage assets located in the Eagle Ford Shale in South Texas, which we sold in October 2020.
White Star	White Star Petroleum, LLC.

ENLINK MIDSTREAM, LLC

PART I

Item 1. Business

General and Recent Developments

Formation

ENLC is a Delaware limited liability company formed in October 2013. EnLink Midstream, LLC common units are traded on the NYSE under the symbol “ENLC.” 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 terms “Company” or “Registrant” as well as the terms “ENLC,” “our,” “we,” and “us” or like terms are sometimes used as references to EnLink Midstream, LLC itself or EnLink Midstream, LLC and its consolidated subsidiaries, including ENLK.

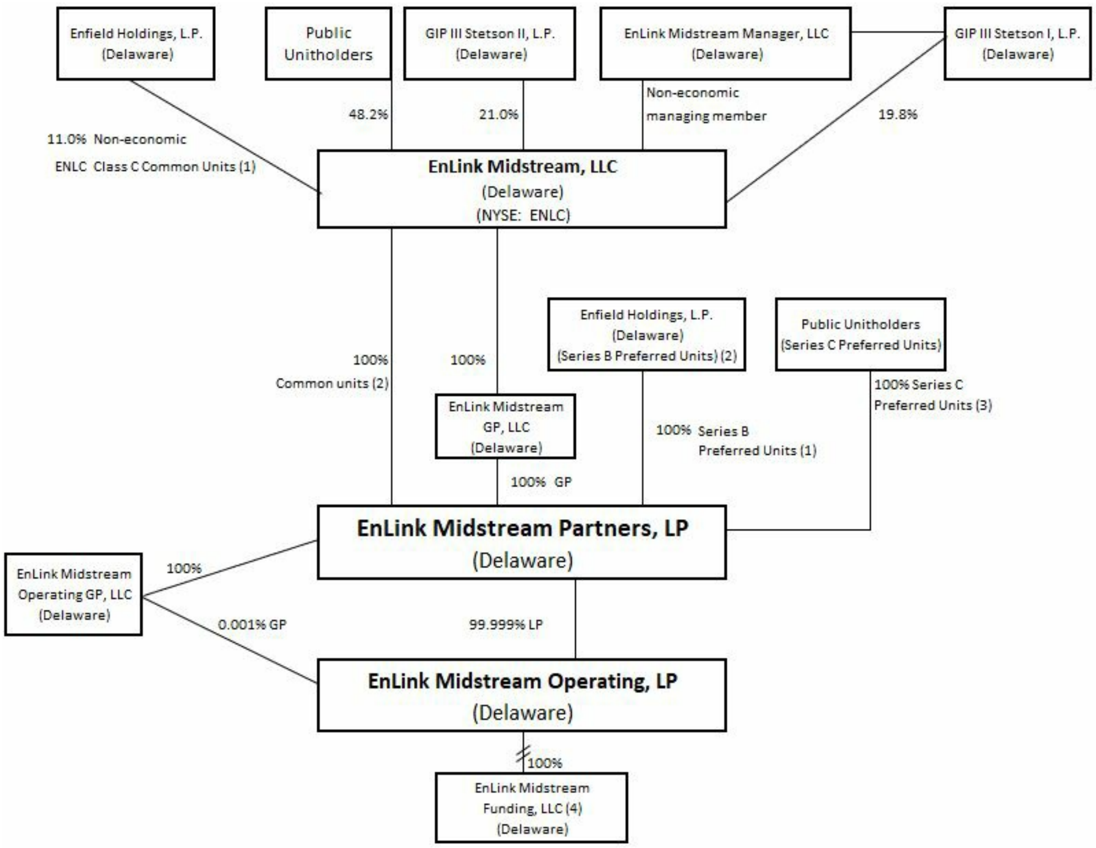
ENLC owns all of ENLK’s common units and also owns all of the membership interests of the General Partner. References in this report to “EnLink Midstream Partners, LP,” the “Partnership,” “ENLK,” or like terms refer to EnLink Midstream Partners, LP itself or EnLink Midstream Partners, LP together with its consolidated subsidiaries, including EnLink Midstream Operating, LP.

On July 18, 2018, GIP acquired control of us and our Managing Member. See “Item 8. Financial Statements and Supplementary Data – Note 1” for more information on the GIP Transaction.

Additional Information

For more information about our organization of business or developments prior to 2020, refer to “Item 1. Business—General” of our Annual Report on Form 10-K for the fiscal year ended December 31, 2019, filed with the Commission on February 26, 2020, and available here.

The following diagram depicts our organization and ownership as of December 31, 2020:



(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.
(4) EnLink Midstream Funding, LLC is a bankruptcy-remote special purpose entity that entered into the AR Facility in October 2020. See “Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations—Recent Developments Affecting Industry Conditions and Our Business” for additional information.

Current Market Environment

On March 11, 2020, the World Health Organization declared the ongoing coronavirus (COVID-19) outbreak a pandemic and recommended containment and mitigation measures worldwide. The ongoing pandemic has reached every region of the globe and has resulted in widespread adverse impacts on the global economy, on the energy industry as a whole and on midstream companies, and on our customers, suppliers, and other parties with whom we have business relations. The pandemic and related travel and operational restrictions, as well as business closures and curtailed consumer activity, have resulted in a reduction in global demand for energy, volatility in the market prices for crude oil, condensate, natural gas and NGLs, and a significant reduction in the market price of crude oil during the first half of 2020. As a result of the demand destruction, reduced commodity prices, and an uncertain timeline for full recovery, many oil and natural gas producers, including some of our customers, curtailed their current drilling and production activity and reduced or slowed down their plans for future drilling and production activity. As a result of these decreases in producer activity, we experienced reduced volumes gathered, processed, fractionated, and transported on our assets in some of the regions that supply our systems during the first half of 2020Although volumes have since been restored nearly to pre-pandemic levels, capital investments by oil and natural gas producers remain at low levels.

Since the outbreak began, our first priority has been the health and safety of our employees and those of our customers and other business counterparties. In March, we implemented preventative measures and developed a response plan to minimize unnecessary risk of exposure and prevent infection, while supporting our customers' operations, and we continue to follow these plans. We maintain a crisis management team for health, safety and environmental matters and personnel issues and a cross-functional COVID-19 response team to address various impacts of the situation, as they develop. We also continue to follow modified business practices (including discontinuing non-essential business travel, implementing work-from-home policies during high-transmission periods, and staggered work-from-home policies for employees who can execute their work remotely in order to reduce office density, and encouraging employees to adhere to local and regional social distancing recommendations) to support efforts to reduce the spread of COVID-19 and to conform to government restrictions and best practices encouraged by the Centers for Disease Control and Prevention, the World Health Organization, and other governmental and regulatory authorities. We also have promoted heightened awareness and vigilance, hygiene, and implementation of more stringent cleaning protocols across our facilities and operations. We continue to evaluate and adjust these preventative measures, response plans and business practices with the evolving impacts of COVID-19.

There is considerable uncertainty regarding how long the COVID-19 pandemic will persist and affect economic conditions and the extent and duration of changes in consumer behavior, such as the reluctance to travel, as well as whether governmental and other measures implemented to try to slow the spread of the virus, such as large-scale travel bans and restrictions, border closures, quarantines, shelter-in-place orders, and business and government shutdowns that exist as of the date of this report will be extended or whether new measures will be imposed. A sustained significant decline in oil and natural gas exploration and production activities and related reduced demand for our services by our customers, whether due to decreases in consumer demand or reduction in the prices for oil, condensate natural gas and NGLs or otherwise, would have a material adverse effect on our business, liquidity, financial condition, results of operations, and cash flows (including our ability to make distributions to our unitholders).

As of the date of this report, our efforts to respond to the challenges presented by the conditions described above and minimize the impacts to our business have yielded results. Our systems, pipelines, and facilities have remained operational throughout the period. We have also moved quickly and decisively, and we continue to adapt and respond promptly, to implement strategies to reduce costs, increase operational efficiencies, and lower our capital spending. We reduced our capital expenditures in 2020, including both growth and maintenance capital expenditures, to $262.6 million, a 65% reduction from 2019 total capital spending. We have also reduced costs across our platform. We reduced our general and administrative and operating expenses by $142.6 million for the year ended December 31, 2020 compared to the year ended December 31, 2019. We have not requested any funding under any federal or other governmental programs related to COVID-19 to support our operations, and we do not expect to utilize any such funding. We are continuing to address concerns to protect the health and safety of our employees and those of our customers and other business counterparties, and this includes changes to comply with health-related guidelines as they are modified and supplemented.

We cannot predict the full impact that the COVID-19 pandemic or the volatility in oil and natural gas markets related to COVID-19 will have on our business, liquidity, financial condition, results of operations, and cash flows (including our ability to make distributions to unitholders) at this time due to numerous uncertainties. The ultimate impacts will depend on future developments, including, among others, the ultimate duration and persistence of the pandemic, the speed at which the population is vaccinated against the virus and the efficacy of the vaccines, the effect of the pandemic on economic, social and other aspects of everyday life, the consequences of governmental and other measures designed to prevent the spread of the virus, actions taken by members of OPEC+ and other foreign, oil-exporting countries, actions taken by governmental authorities, customers, suppliers, and other third parties, and the timing and extent to which normal economic, social and operating conditions resume.

For additional discussion regarding risks associated with the COVID-19 pandemic, see "Item 1A—Risk Factors—The ongoing coronavirus (COVID-19) pandemic has adversely affected and could continue to adversely affect our business, financial condition, and results of operations."

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 11,900 miles of pipelines, 22 natural gas processing plants with approximately 5.5 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, or barge, truck, or rail terminal.

We manage and report our activities primarily according to the nature of activity and geography. We have five reportable 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;

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

- *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;

- *North Texas Segment.* The North Texas segment includes our natural gas gathering, processing, and transmission activities in North Texas; 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 15."

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 while growing prudently and profitably. We intend to accomplish this objective by executing the following strategies:

- *Operational Excellence and Innovation*. We have created a rigorous company-wide program that we refer to as the EnLink Way centered on innovation and continuous improvement in our business. We believe this program will allow us to optimize our operations in order to enhance the profitability of current operations, capture capital-efficient commercial opportunities in a lower-activity environment, and enhance the scalability of our asset platforms for future growth.

- *Financial Discipline and Flexibility*. We are focused on strengthening our financial position and flexibility by generating significant cash flows, driving disciplined capital allocation, and maintaining liquidity and balance sheet strength. We believe that our financial discipline will afford us better access to the capital markets and a competitive cost of capital, and the opportunity to grow our business in a prudent manner throughout the cycles in our industry.

- *Sustainability and Safety*. Sustainability and safety are integrated into all aspects of our business. Approximately 90% of our current business is focused on natural gas and natural gas liquids, which we believe will continue to be important sources of clean energy for decades to come. We have published a sustainability report with key metrics showing improvements each of the last two years, and are developing sustainability goals for the next several years. To achieve those goals, we are evaluating opportunities to reduce or offset emissions in our operations using process improvements and technology, or utilizing renewable energy. With respect to safety, we are committed to operating with the highest standards in our industry. During 2020, EnLink had its best safety year on record with the lowest number of reportable incidents in our history.

- *Strategic Growth.* 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 are also focused on economically attractive organic expansion opportunities in our areas of operation that allow us to leverage our existing infrastructure, operating expertise, and customer relationships, as well as to increase our natural gas and NGL presence downstream.

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, 2020:

Gathering and Transmission Pipelines	Approximate Length (Miles)	Compression (HP)	Estimated Capacity (1)	Year Ended December 31, 2020 Average Throughput (2)
Gas Pipelines				
Permian assets:				
MEGA System gathering facilities	825	159,270	545	521,000
Delaware gathering system (3)	235	59,200	280	369,800
Permian gas assets (3)	1,060	218,470	825	890,800
Louisiana assets:				
Louisiana gas gathering and transmission system	3,040	97,400	3,975	1,993,900
Oklahoma assets:				
Central Oklahoma gathering system	1,830	211,490	1,180	1,087,500
Northridge gathering system	140	14,000	65	29,000
Oklahoma gas assets	1,970	225,490	1,245	1,116,500
North Texas assets:				
Bridgeport rich and lean gathering systems	2,780	197,000	869	699,900
Johnson County gathering system	385	49,000	400	99,800
Silver Creek gathering system	890	45,000	217	235,500
Acacia transmission system	130	16,000	920	443,000
North Texas gas assets	4,185	307,000	2,406	1,478,200
Total Gas Pipelines	10,255	848,360	8,451	5,479,400
NGL, Crude Oil, and Condensate Pipelines				
Permian assets:				
Permian Crude Oil and Condensate assets	470	—	188,500	116,200
Louisiana assets:				
Cajun-Sibon NGL pipeline system	760	—	185,000	178,300
Ascension NGL pipeline (4)	35	—	50,000	16,900
Ohio River Valley (5)	210	—	17,370	16,900
Louisiana NGL, Crude Oil, and Condensate assets	1,005	—	252,370	212,100
Oklahoma assets:				
Central Oklahoma crude oil gathering systems	195	—	160,000	28,700
Total NGL, Crude Oil, and Condensate Pipelines	1,670	—	600,870	357,000

(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 Delaware gathering system includes only the Delaware Basin JV's compression capacity and does not include gas compressed by third parties on our system.
(4) Includes gross mileage, capacity, and throughput for the Ascension JV, which is owned 50% by us.
(5) Estimated capacity is comprised of trucking capacity only.

Processing Facilities	Processing Capacity (MMcf/d)	Year Ended December 31, 2020 Average Throughput (MMbtu/d)
Permian assets:		
MEGA system processing facilities	528	551,200
Delaware processing facilities (1)	635	347,800
Permian assets	1,163	899,000
Louisiana assets:		
Louisiana gas processing facilities (2)	1,778	193,000
Oklahoma assets:		
Central Oklahoma processing facilities (3)	1,245	1,028,100
Northridge processing facility	200	77,800
Oklahoma assets	1,445	1,105,900
North Texas assets:		
Bridgeport processing facility	800	532,900
Silver Creek processing system (4)	280	138,100
North Texas assets	1,080	671,000
Total Processing Facilities	5,466	2,868,900

(1) The Lobo processing facilities and the Tiger plant represent 395 MMcf/d and 240 MMcf/d, respectively, of the total processing capacity of the Permian gas processing facilities. The Tiger plant is not operating at this time.

(2) The Blue Water, Eunice, Plaquemine, and Sabine processing plants are not operational. These plants represent 193 MMcf/d, 350 MMcf/d, 225 MMcf/d, and 300 MMcf/d, respectively, of the total processing capacity of the Louisiana gas processing facilities.

(3) The Battle Ridge processing plant is not operational and represents 85 MMcf/d of the total processing capacity of the Central Oklahoma processing facilities. In December 2020, we began moving equipment and facilities previously associated with the Battle Ridge processing plant in Central Oklahoma to the Permian Basin. Additionally, the Thunderbird plant is not operating at this time and represents 200 MMcf/d of the total processing capacity of the Central Oklahoma processing facilities.

(4) 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.

Fractionation Facilities	Estimated NGL Fractionation Capacity (Bbls/d)	Year Ended December 31, 2020 Average Throughput (Bbls/d)
Permian assets:		
Mesquite terminal (1)	15,000	—
Louisiana assets:		
Plaquemine fractionation facility (2)	125,000	82,500
Plaquemine processing plant	5,000	3,100
Eunice fractionation facility	70,000	62,500
Riverside fractionation facility (2)	—	32,800
Louisiana assets	200,000	180,900
North Texas assets:		
Bridgeport processing facility (3)	22,000	—
Corporate assets:		
GCF (4)	56,000	32,500
Total Fractionation Facilities	293,000	213,400

(1) The Mesquite terminal fractionator is not operational.
(2) 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 125,000 Bbls/d.
(3) 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 these facilities, so throughput volumes through these facilities are not captured on a routine basis and are not significant to our adjusted gross margins.
(4) Volumes shown reflect our 38.75% ownership in GCF. The GCF fractionation facility is currently idled.

Storage Assets	Storage Type	Year Ended December 31, 2020 Estimated Storage Capacity (1)
Permian assets:		
Avenger storage	Crude	0.1
Louisiana assets:		
Belle Rose gas storage facility	Gas	11.9
Sorrento gas storage facility	Gas	6.4
Jefferson Island storage facility	Gas	2.5
Napoleonville NGL storage facility	NGL	6.8
ORV storage	Crude	0.7
Oklahoma assets:		
Central Oklahoma storage	Crude	0.2

(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.

  - *Delaware gas gathering system.* This rich natural gas gathering system consists of gathering pipeline and compression assets in the Delaware Basin in Texas and New Mexico. These gathering systems are connected to our Lobo processing facilities and Tiger plant, which are 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 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.

- Gas Processing Facilities. Our Permian Basin gas processing facilities include seven 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 175 MMcf/d, and the Riptide processing facility with a capacity of 220 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 220 MMcf/d of processing capacity, respectively. The Lobo processing facilities and the connected gathering system are owned by the Delaware Basin JV.

  - *Tiger plant.* Our Tiger plant is located in Culberson County, Texas, and accounts for 240 MMcf/d of processing capacity. The Tiger plant is owned by the Delaware Basin JV. The Tiger plant was idled in 2020. We expect to operate the Tiger plant again when there is a sustained need for the additional processing volumes on our Delaware Basin processing assets.

- 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 have idled the Mesquite fractionator and only operate the condensate stabilizer in the Mesquite terminal, which has a capacity of 5,000 Bbls/d.

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 three storage facilities. These assets consist of the following:

   - *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.

   - *Jefferson Island Storage Facility.* The Jefferson Island storage facility and pipeline header system is located in Iberville and Vermilion Parishes in Louisiana. In December 2020, we acquired the Jefferson Island storage facility, which includes 2.5 Bcf of natural gas storage capacity that is connected to our extensive Louisiana natural gas system.

   - *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.

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

      - *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.

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.

  - *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 plant (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 Thunderbird plant is not operating at this time.

        - The unprocessed NGLs from the Chisholm plants are transported by ONEOK, Inc. (“ONEOK”) to NGL transmission lines, which then transport the NGLs to our fractionators in Louisiana.

        - The processing facility at the Battle Ridge plant was idled due to decreased volumes. In December 2020, we began moving equipment and facilities previously associated with the Battle Ridge processing plant in Central Oklahoma to the Permian Basin. We expect to complete the relocation in the second half of 2021.

        - The residue natural gas from the Cana plant is delivered to Enable Midstream Partners, LP and an affiliate of ONEOK. Devon is the primary customer of the Cana plant. We have extended our fixed-fee processing agreement with Devon, which was effective after the GIP Transaction, and currently have approximately eight 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 plant.

    - *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.

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 was the largest customer on the Bridgeport rich gas gathering system contributing substantially all of the natural gas gathered for the year ended December 31, 2020. In October 2020, Devon sold its Barnett Shale assets to BKV. As a result of this sale, we have a fixed-fee gathering agreement with BKV and currently have approximately eight years remaining on a fixed-fee gathering agreement 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 was primarily attributable to Devon for the year ended December 31, 2020 and was 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 BKV 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 three 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 Inc, Energy Transfer Partners, Enterprise Product Partners, and GDF Suez. Devon, who sold their Barnett Shale assets to BKV in October 2020, was the largest customer on the Acacia pipeline for the year ended December 31, 2020. We currently have approximately three years remaining on a fixed-fee transportation agreement with BKV 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, is one of the largest processing plants in the U.S. with seven cryogenic turboexpander plants. Devon, who sold their Barnett Shale assets to BKV in October 2020, was the Bridgeport facility's largest customer in 2020, providing substantially all of the natural gas processed for the year ended December 31, 2020. As described above, we are party to a fixed-fee processing agreement with BKV and currently have approximately eight years remaining on our agreement with BKV pursuant to which we provide processing services for natural gas delivered 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, 200 MMcf/d, and 30 MMcf/d of processing capacity, respectively. During 2018, we idled the Azle and Goforth plants due to decreased volumes, and these plants remain non-operational. 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 adjusted gross margin.

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. Beginning in January 2021, the GCF assets have been temporarily idled to reduce operating expenses. We expect these assets to resume operations when there is a sustained need for additional fractionation capacity in Mont Belvieu.

- *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.

Organic Growth

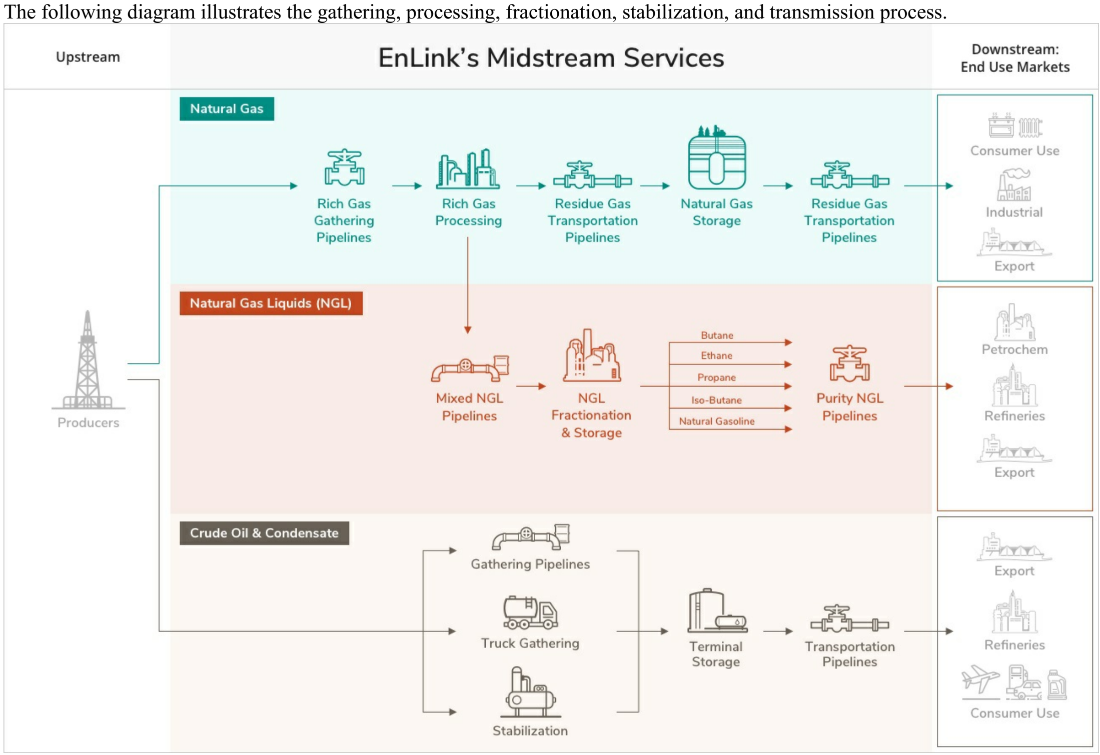
War Horse Processing Plant. In December 2020, we began moving equipment and facilities previously associated with the Battle Ridge processing plant in Central Oklahoma to the Permian Basin. This relocation is expected to increase the processing capacity of our Permian Basin processing facilities by approximately 80 MMcf/d. We expect to complete the relocation in the second half of 2021.

Riptide Processing Plant. The Riptide processing plant is a gas processing plant located in the Midland Basin. In March 2020, we completed an expansion to the Riptide processing plant, which increased the processing capacity by 55 MMcf/d. As of December 31, 2020, the total operational processing capacity of the Riptide processing plant was 220 MMcf/d.

Tiger Plant. The Tiger plant is a gas processing plant located in the Delaware Basin. This processing plant is owned by the Delaware Basin JV. In August 2020, we completed the construction of the Tiger plant, which expanded our Delaware Basin processing capacity by an additional 240 MMcf/d, to handle expected future processing volume growth. The Tiger plant is not operating at this time.

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 greater 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 and the ongoing effects of the COVID-19 pandemic on our industry and our customers 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 adjusted gross 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,		
	2020	2019	2018
Devon	14.4 %	10.5 %	10.4 %
Dow Hydrocarbons and Resources LLC	13.2 %	10.0 %	11.1 %
Marathon Petroleum Corporation	12.2 %	13.8 %	11.5 %

Regulation

Natural Gas Pipeline Regulation. We own an interstate natural gas pipeline that is subject to regulation as a natural gas company by 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 a fact-intensive analysis, 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.

Additionally, 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. In December 2020, the President of the United States signed the Protecting our Infrastructure of Pipelines and Enhancing Safety Act of 2020 (the "PIPES Act"), which reauthorizes PHMSA's oil and gas pipeline programs through 2023 and imposes additional mandates on the agency. For example, the law requires, among other things, rulemaking to amend the integrity management program, emergency response plan, operation and maintenance manual, and pressure control recordkeeping requirements for gas distribution operators; to create new leak detection and repair program obligations; and to set new minimum federal safety standards for onshore gas gathering lines. Additionally, PHMSA's maximum civil penalties were increased in January 2021.

On January 23, 2017, PHMSA issued a final rule amending its 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 added 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. On January 11, 2021, PHMSA issued another final rule amending its pipeline safety regulations to ease regulatory burdens on the construction, operation, and maintenance of gas transmission, distribution, and gathering pipeline systems. The amendments also modified the monetary threshold for reporting to PHMSA incidents that result in property damage from $50,000 to $122,000.

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. The associated notice of proposed rulemaking, issued October 14, 2020, proposes an integrity management alternative for managing class location changes in areas that increase in population density from Class 1 to Class 3 locations.

In October 2019, PHMSA issued three new final rules. One rule, effective in December 2019, 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, effective in July 2020, 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.

On January 20, 2021, the Acting Secretary for the Department of the Interior signed an order suspending new fossil fuel leasing and permitting on federal lands, including offshore pipeline leases, for 60 days. If our customers are unable to secure permits, sustained reductions in exploration or production activity in our areas of operation could lead to reduced utilization of our pipeline and terminal systems or reduced rates under renegotiated transportation or storage agreements. We are still evaluating the effects of the recent order on our operations and our customers' operations, but our inability and our customers' inability to secure required permits could adversely affect our business, financial condition, results of operation or cash flows, including our ability to make cash distributions to our unitholders.

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

Recent Developments. On January 20, 2021, the Biden Administration came into office and immediately issued a number of executive orders related to environmental matters that could affect our operations and those of our customers, including an Executive Order on "Protecting Public Health and the Environment and Restoring Science to Tackle the Climate Crisis" seeking to adopt new regulations and policies to address climate change and suspend, revise, or rescind, prior agency actions that are identified as conflicting with the Biden Administration's climate policies. Among the areas that could be affected by the review are regulations addressing methane emissions and the part of the extraction process known as hydraulic fracturing. The Biden Administration has also issued other orders that could ultimately affect our business, such as the executive order rejoining the Paris Agreement, and could seek, in the future, to put into place additional executive orders, policy and regulatory reviews, and seek to have Congress pass legislation that could adversely affect the production of oil and gas assets and our operations and those of our customers.

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. The 2015 standards were challenged before the U.S. Court of Appeals for the D.C. Circuit. On August 23, 2019, the D.C. Circuit upheld the EPA's primary ozone standard and remanded the secondary standard to EPA for reconsideration. The implementation of these standards could result in stricter permitting requirements, delays or prohibitions on 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 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 September 2020, the EPA published two additional final rules that removed sources in the transmission and storage segment from the regulated source category of the 2016 NSPS, rescinded the NSPS (including both VOC and methane requirements) applicable to those sources, and rescinded the methane-specific requirements of the NSPS applicable to sources in the production and processing segments. EPA's September 2020 rules are being challenged in the U.S. Circuit Court for the D.C. Circuit. In addition, on January 21, 2021, President Biden issued an Executive Order on "Protecting Public Health and the Environment and Restoring Science to Tackle the Climate Crisis" directing EPA to consider publishing for notice and comment, by September 2021, a proposed rule suspending, revising, or rescinding the 2020 NSPS for the oil and natural gas sector.

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, 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 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. In July 2020, the U.S. District Court for the Northern District of California vacated BLM's 2018 revision rule. Additionally, in October 2020, a Wyoming federal district judge vacated the 2016 venting and flaring rule. 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 Biden 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, on January 21, 2021, President Biden issued an Executive Order on "Protecting Public Health and the Environment and Restoring Science to Tackle the Climate Crisis" seeking to adopt new regulations and policies to address climate change and suspend, revise, or rescind, prior agency actions that are identified as conflicting with the Biden Administration's climate policies.

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 and withdrew from the agreement in November 2020. However, on January 20, 2021, President Biden signed an instrument that reverses this withdrawal, and the United States will formally re-join the Paris Agreement on February 19, 2021. 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 April 2020, EPA and USACE issued a new final 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 and April 2020 final rules to repeal the 2015 WOTUS definition are currently before multiple federal district courts. Additionally, the rules are among agency actions listed for review in accordance with President Biden's January 20, 2021 Executive Order: "Protecting Public Health and the Environment and Restoring Science to Tackle the Climate Crisis." If the rules are 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 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 ("ODNR") rules that took effect October 1, 2012. These rules set 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 ODNR 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 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. The final rule was challenged in the U.S. District Court for the Northern District of California almost immediately after issuance. On March 27, 2020, the District Court upheld the BLM's rescission of the 2015 rules. This decision is pending appeal in the U.S. Court of Appeals for the Ninth Circuit. 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 lease approximately 157,600 square feet of space at our executive offices in Dallas, Texas under a lease expiring in February 2030. We also lease office space of approximately 56,000 square feet in Midland, Texas, and 47,500 square feet in Houston, Texas under long-term leases, and various other locations to support our operations.

Human Capital

As of December 31, 2020, we (through our subsidiaries) employed 1,069 full-time employees. Of these employees, 231 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.

We strive to provide our employees with a rewarding work environment, including the opportunity for success and a platform for personal and professional development. We are committed to providing a working environment that empowers our employees, allows them to execute at their highest potential, keeps them safe, and promotes their professional growth.

The safety of our employees is a key management priority. We maintain strict safety protocols and require quarterly safety training for all field employees and annual safety training for corporate employees. During 2020, EnLink had its best safety year on record with the lowest number of reportable incidents in our history. We require annual safety training by every employee. Additional hours of safety training are required for field personnel.

We also see value in having a diverse and inclusive environment. At December 31, 2020, women represented approximately 39% of the positions at our corporate offices in Dallas and Houston and held approximately 36% of all manager and above positions in those offices. At the same date, minorities represented approximately 27% of the manager and above positions at our corporate offices in Dallas and Houston and held approximately 19% of all manager and above positions company-wide. Additionally, women and minorities each constituted 14% of all officers company-wide. We also require yearly anti-harassment and discrimination training for all employees.

For more information on our employee initiatives, see the "Our People" section of our current Sustainability Report (located on our website at enlink.com) regarding our Human Capital programs and initiatives. In addition, see "General and Recent Developments—Current Market Environment" for more information regarding our actions to prioritize the health and safety of our employees with respect to the COVID-19 pandemic.

Sustainability

We are committed to sustainable business practices, including safe, responsible and ethical operations, respect for the environment, a focus on customers, and support for our team of employees. We maximize safe operations of our assets by focusing on mitigating risk, routinely increasing knowledge and skills of our employees, improving our processes, and measuring our performance. We link short-term incentive compensation for our employees to our safety standards and performance in order to promote a safety-centric culture. We are also committed to environmental stewardship by operating our assets and constructing new facilities in order to minimize our footprint and environmental impact, control pollution and conserve resources. We focus on serving our customers safely and reliability and providing the highest level of service through innovation and continuous improvement processes in our business. We support our employees by providing competitive pay and benefits, training, and a respectful and inclusive culture.

We formed an executive sponsored, cross-functional committee, comprised of leaders from various departments of our company, to put into action our commitment to sustainable business practices. In addition, we publish an annual sustainability report, which provides both accountability to us regarding sustainable business practices as well as transparency to our stakeholders regarding our commitment to, and progress toward, becoming a more sustainable company.

Environmental Responsibility

We strive for safe operations that minimize our environmental impact. We demonstrate that commitment by complying with applicable environmental laws, focusing on prevention of spills and emissions of unpermitted substances into the atmosphere, reducing our impact on land, waterways, and wildlife habitats, and managing our resource consumption to minimize waste. We have also adopted technologies that support the continuous improvement of our operations to minimize their environmental impact.

We work to operate our assets in a way that maximizes their usefulness, reliability, and safe operations, including through the use of smart tool runs, pressure testing, cathodic protection and robust corrosion management, and routine tests of our assets. We utilize the latest technology to monitor and operate our pipeline systems, such as leak detection monitoring software and vibration monitoring of our compressor stations, which accelerates response time to potential incidents and increases our reliability. We also hold numerous safety trainings for our employees each month and require employees to attend based on their job position.

We attempt to minimize our environmental impact through our operations. Many of our facilities are self-powered, generating energy from the hydrocarbons being processed and reducing the need for public grid connection. We also employ processes that allow us to repurpose exhaust heat, a byproduct of operations, for warming purposes required elsewhere in our process. We utilize solar capabilities to power our methanol pumps, meter stations, and line operating data gathering stations, reducing our need for additional power. We maintain a robust leak detection and repair program and have implemented infrared optical gas image surveys at most of our facilities. To improve emissions performance and operational efficiency, we replaced flares with thermal oxidizers at many of our plants, and we installed vapor recovery units and exhaust catalysts and rerouted compressor blowdown gas back into our system at many of our compressor stations.

We also reuse our resources to limit our waste production. We focus on repurposing and refurnishing idle materials and equipment to be used in new ways at other facilities, including meters, filter separators, compressors, treaters, scrubbers, dehydration systems, amine systems, process vessels, cylinders, valves, pipe, tanks, and pig traps.

We seek to minimize impacts from the construction of our facilities and other operations as well. We first identify site options during the project planning phase to avoid wetlands, habitats, and other environmentally sensitive areas, when possible. Once operational, we partner closely with regulatory agencies to ensure we are compliant with environmental regulations. We also generally restore land to preconstruction conditions, often beyond the footprint that we utilize.

Social Responsibility

We provide our employees with a rewarding work environment, providing a platform for personal and professional development. We focus on providing a working environment that empowers, and invests in, our employees. We often participate in community events throughout our area of operations each year, and we encourage our employees to participate in at least one community service project each year.

We provide competitive pay packages that support the financial security of our employees and help attract and retain top talent. Our pay packages, comprised of base salary, short-term incentive bonuses tied to company performance, comprehensive employee benefits, and paid leave, align the incentives of our employees to those of our company. We also have a wellness initiative that encourages employees and their spouses to receive an annual wellness checkup.

Governance

The Board of Directors of the Managing Member (the “Board”) includes directors with extensive energy, finance, sustainability, and public company governance experience. The compensation of our executives is determined and approved by the Governance and Compensation Committee (the “Compensation Committee”) of the Board, which Compensation Committee includes independent directors. The determination of executive compensation includes an analysis of the evolving demands of the industry, assessment of individual contributions to the business strategy, and an in-depth comparison of the compensation practices of a defined peer company group. We foster a strong culture of ownership among our executives and align the interests of our leaders with those of our stakeholders by tying the performance of the company to the short-term and long-term compensation of our executives.

We require our employees to complete annual training courses related to our corporate policies, including our Code of Business Conduct and Ethics, which outlines our requirements to maintain a work culture based on integrity, ethics, and safe and fair business dealings. We also identify and prioritize the risks associated with our business each quarter through our enterprise risk management program, conducted by leaders throughout our business. We identify top risks to our business and regularly review them with the Board, including through biannual meetings held with the Board and the Audit Committee of the Board.

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. In that case, we may be unable to make distributions to our unitholders and the trading price of our common units could decline. In this report, the terms "Company" or "Registrant," as well as the terms "ENLC," "our," "we," "us" or like terms, are sometimes used to refer to EnLink Midstream, LLC itself or EnLink Midstream, LLC and its consolidated subsidiaries, including ENLK and its consolidated subsidiaries. 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.

Risk Factor Summary

The following is a summary of risk factors that could adversely impact our financial condition, results of operations, or cash flows:

Risks Inherent in an Investment in ENLC

Risks Inherent to an Investment in ENLC include the following risks:

- GIP owns approximately 45.8% of our outstanding common units as of February 11, 2021and controls the Managing Member, and therefore, GIP could favor GIP's own interests to the detriment of our unitholders in any conflict of interest;
- GIP may compete with us and is not required to offer us the opportunity to acquire additional assets or businesses;
- costs reimbursements due to the Managing Member and its affiliates will be determined by the Managing Member and could be substantial;
- our operating agreement replaces fiduciary duties otherwise owed to our unitholders with limited contractual standards;
- our operating agreement restricts remedies available to our unitholders for actions of the Managing Member, and unitholders cannot remove the Managing Member without its consent without a vote of the holders of at least 66 2/3% of all outstanding ENLC common units;
- unitholders have limited voting rights and are not entitled to elect the Managing Member or its directors;
- a default under GIP's credit facility could result in a change in control and a default under some of our debt agreements;
- our operating agreement restricts the voting rights of unitholders owning more than 20% of our units;
- control of the Managing Member may be transferred to a third party without unitholder consent;
- we may issue additional units, including senior units, without the approval of holders of common units;
- the holders of Series B Preferred Units have certain rights related to our business and management and the preferred units may be exchanged for our common units, diluting common unitholders;
- GIP may sell common units, which could adversely impact the trading price of common units;
- our Managing Member has a call right that may require unitholders to sell their common units at an undesirable time or price;
- unitholders may have liability to repay distributions that were wrongfully distributed to them;
- the price of our common units may fluctuate significantly; and
- we are a "controlled company" under NYSE rules and rely on exemptions from certain listing requirements.

Financial and Indebtedness Risks

Financial and Indebtedness Risks include the following risks:

- our cash flow consists almost exclusively of cash flows from ENLK, and we may not have sufficient cash available to pay distributions to unitholders each quarter;
- our debt agreements may restrict our current and future operations;
- 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;

- changes in the availability and cost of capital, as a result of a change in our credit rating, could increase our financing costs and reduce our cash available for distribution;
- impairments to goodwill, long-lived assets and equity method investments could reduce our earnings;
- exposure to credit risk of our customers and counterparties could have an adverse effect on our financial condition;
- interest rate increases could adversely impact the price of ENLC’s common units, our ability to issue equity or incur indebtedness, and our ability to make cash distributions;
- we may not realize our deferred tax assets;
- entity level corporate income taxes will reduce cash available for distributions to common unitholders; and
- changes in determining LIBOR under our debt agreements may adversely impact interest expense.

Business and Industry Risks

Business and Industry Risks include the following risks:

- the ongoing coronavirus (COVID-19) pandemic continues to adversely affect our business, financial condition, and results of operation;
- our dependency on Devon for a substantial portion of the natural gas that we gather, process, and transport could result in a decline in our operating results and cash available for distribution, and developments that materially and adversely affect Devon could adversely affect us;
- our inability to retain existing customers or acquire new customers would reduce our revenues and limit our future profitability;
- decreases in the volumes that we gather, process, fractionate, or transport would adversely affect our financial condition, results of operations, or cash flows;
- volumes we service in the future could be less than we anticipate as a result of uncertainty regarding hydrocarbon reserves, which could have a material adverse effect on our financial condition, results of operations, or cash flows;
- any inability to balance our purchases and sales under our sale and purchase arrangements would increase our exposure to commodity price risks and could cause volatility in our operating income;
- adverse developments in the midstream business would adversely affect our financial condition and results of operations and reduce our ability to make distributions;
- competition for crude oil, condensate, natural gas, and NGL supplies and any decrease in the availability of such commodities, volatile prices and market demand for crude oil, condensate, natural gas, and NGLs that are beyond our control could each adversely affect our financial condition, results of operation, or cash flows;
- reductions 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;
- increasing scrutiny and changing expectations from stakeholders with respect to our environment, social, and governance practices may impose additional costs on us or expose us to new or additional risks;
- future growth may be limited if we are unable to make acquisitions on economically acceptable terms and integrate assets into our asset base effectively;
- disruption of our assets due to costs to acquire rights-of-way or leases could cause us to cease operations on the affected land, increase costs related to continuing operations elsewhere, and reduce our revenue;
- occurrence of a significant accident or other event not fully insured could adversely affect our operations and financial condition;
- risks to conduct of certain operations through joint ventures could have a material adverse effect on the success of these operations, our financial position, results of operations, or cash flows;
- unavailability of third-party pipelines or midstream facilities interconnected to our assets could adversely affect our adjusted gross margin and cash flow;
- vulnerability to weather-related risks, particularly for our South Louisiana and Texas Gulf Coast assets could adversely impact our financial condition, results of operations, or cash flows;
- loss of key members of management or the failure to retain an appropriately qualified workforce could disrupt our business operations or have a material adverse effect on our business and results of operations;
- fluctuations in commodity prices and interest rates could result in financial losses or reduce our income; and
- terrorist or cyberattack or a failure of our computer systems may adversely affect our ability to operate our business.

Environmental, Legal Compliance, and Regulatory Risks

Environmental, Legal Compliance, and Regulatory Risks include the following risks:

- 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 could adversely impact our revenues and results of operation;
- climate change legislation and regulatory initiatives could result in increased operating costs and reduced demand for the natural gas and NGL services we provide;
- our ability to receive or renew required permits and other approvals from governmental authorities or other third parties could impact our operations;
- federal and state rate and service regulation on our natural gas or liquids pipelines could limit our revenues;
- compliance with pipeline safety regulations could increase our operating costs;
- compliance with existing or new environmental laws and regulations could increase our operating costs;
- recent rules under the Clean Air Act could increase our capital expenditures and operating costs and reduce demand for our services;
- restrictions on our operations imposed by the ESA and MBTA could have an adverse impact on our operations;
- derivatives legislation adversely affecting our ability to hedge risk could have a material adverse effect on us, our financial conditions, and our results of operation; and
- compliance with privacy and data protection laws could increase our operating costs.

Risks Inherent in an Investment in ENLC

GIP owns approximately 45.8% of ENLC's outstanding common units as of February 11, 2021 and controls the Managing Member, which has sole responsibility for conducting our business and managing our operations. Our Managing Member and its affiliates, including GIP, have conflicts of interest with us and limited duties to us and may favor their own interests to your detriment.

GIP owns and controls the Managing Member and appoints all of the directors of the Managing Member. Some of the directors of the Managing Member, including directors with a majority of the voting power of the board of directors of the Managing Member, are also directors or officers of GIP. Although the Managing Member has a duty to manage us in a manner it subjectively believes to be in, or not opposed to, our best interests, the directors and officers of the Managing Member also have a duty to manage the Managing Member in a manner that is in the best interests of GIP, in its capacity as the sole member of the Managing Member. Conflicts of interest may arise between GIP and its affiliates, including the Managing Member, on the one hand, and us and our unitholders, on the other hand. In resolving these conflicts of interest, the Managing Member may favor its own interests and the interests of its affiliates over the interests of our unitholders. These conflicts include, among others, the following situations:

- neither our operating agreement nor any other agreement requires GIP to pursue a business strategy that favors us or to enter into any commercial or business arrangement with us. GIP's directors and officers have a fiduciary duty to make decisions in the best interests of the owners of GIP, which may be contrary to our interests;

- GIP may be constrained by the terms of its debt instruments from taking actions, or refraining from taking actions, that may be in our best interests;

- the Managing Member determines the amount and timing of asset purchases and sales, borrowings, issuance of additional membership interests and reserves, each of which can affect the amount of cash that is available to be distributed to unitholders;

- the Managing Member determines which costs incurred by it are reimbursable by us;

- the Managing Member is allowed to take into account the interests of parties other than us in exercising certain rights under our operating agreement;

- our operating agreement limits the liability of, and eliminates and replaces the fiduciary duties that would otherwise be owed by, the Managing Member and also restricts the remedies available to our unitholders for actions that, without the provisions of the operating agreement, might constitute breaches of fiduciary duty;

- any future contracts between us, on the one hand, and affiliates of GIP, on the other, may not be the result of arm's-length negotiations;
- except in limited circumstances, the Managing Member has the power and authority to conduct our business without unitholder approval;
- the Managing Member may exercise its right to call and purchase all of ENLC's outstanding common units not owned by it and its affiliates if it and its affiliates own more than 90% of ENLC's outstanding common units;
- the Managing Member controls the enforcement of obligations owed to us by the Managing Member and its affiliates, including commercial agreements; and
- the Managing Member decides whether to retain separate counsel, accountants, or others to perform services for us.

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 operating agreement, the doctrine of corporate opportunity, or any analogous doctrine, does not apply to the Managing Member, or any of its affiliates, including GIP and its officers. 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 unitholder 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 the Managing Member and result in less than favorable treatment of us and our unitholders.

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

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

Our operating agreement replaces the fiduciary duties otherwise owed to our unitholders by the Managing Member with contractual standards governing its duties.

Our operating agreement contains provisions that eliminate and replace the fiduciary standards that the Managing Member would otherwise be held to by state fiduciary duty law. For example, our operating agreement permits the Managing Member to make a number of decisions, in its individual capacity, as opposed to in its capacity as the Managing Member, or otherwise, free of fiduciary duties to us and our unitholders. This entitles the Managing Member 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, us, our affiliates or our members. Examples of decisions that the Managing Member may make in its individual capacity include:

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

- whether to exercise its call right;
- how to exercise its voting rights with respect to any membership interests it owns;
- whether or not to consent to any merger or consolidation of us or any amendment to our operating agreement; and
- whether or not to seek the approval of the conflicts committee of the board of directors of the Managing Member, or the unitholders, or neither, of any conflicted transaction.

By purchasing any ENLC common units, a unitholder is treated as having consented to the provisions in our operating agreement, including the provisions discussed above.

Our operating agreement restricts the remedies available to holders of our membership interests for actions taken by the Managing Member that might otherwise constitute breaches of fiduciary duty.

Our operating agreement contains provisions that restrict the remedies available to holders of ENLC common units for actions taken by the Managing Member that might otherwise constitute breaches of fiduciary duty under state fiduciary duty law. For example, our operating agreement provides that:

- whenever the Managing Member makes a determination or takes, or declines to take, any other action in its capacity as the Managing Member, the Managing Member is required to make such determination, or take or decline to take such other action, in good faith, and will not be subject to any other or different standard imposed by Delaware law, or any other law, rule, or regulation, or at equity;
- the Managing Member will not have any liability to us or our unitholders for decisions made in its capacity as a managing member so long as it acted in good faith, meaning that it subjectively believed that the decision was in, or not opposed to, our best interests;
- our operating agreement is governed by Delaware law and any claims, suits, actions, or proceedings:
  - arising out of or relating in any way to our operating agreement (including any claims, suits, or actions to interpret, apply, or enforce the provisions of our operating agreement or the duties, obligations, or liabilities among members or of members to us, or the rights or powers of, or restrictions on, the members or the company);
  - brought in a derivative manner on our behalf;
  - asserting a claim of breach of a fiduciary duty owed by any of our directors, officers, or other employees or the Managing Member, or owed by the Managing Member, to us or our members;
  - asserting a claim arising pursuant to any provision of the Delaware Limited Liability Company Act (“DLLCA”); or
  - asserting a claim governed by the internal affairs doctrine;

  must be exclusively brought in the Court of Chancery of the State of Delaware (or, if such court does not have subject matter jurisdiction thereof, any other court located in the State of Delaware with subject matter jurisdiction), regardless of whether such claims, suits, actions, or proceedings sound in contract, tort, fraud, or otherwise, are based on common law, statutory, equitable, legal, or other grounds, or are derivative or direct claims. By purchasing ENLC common units, a member is irrevocably consenting to these limitations and provisions regarding claims, suits, actions, or proceedings and submitting to the exclusive jurisdiction of the Court of Chancery of the State of Delaware (or such other Delaware courts) in connection with any such claims, suits, actions, or proceedings;
- the Managing Member and its officers and directors will not be liable for monetary damages to us or our members resulting from any act or omission unless there has been a final and non-appealable judgment entered by a court of competent jurisdiction determining that the Managing Member or its officers or directors, as the case may be, acted in bad faith or engaged in fraud or willful misconduct, or, in the case of a criminal matter, acted with knowledge that the conduct was unlawful; and

- the Managing Member will not be in breach of its obligations under our operating agreement or its duties to us or our members if a transaction with an affiliate or the resolution of a conflict of interest is:
    - approved by the conflicts committee of the board of directors of the Managing Member, although the Managing Member is not obligated to seek such approval; or
    - approved by the vote of a majority of the outstanding ENLC common units, excluding any ENLC common units owned by the Managing Member and its affiliates, although the Managing Member is not obligated to seek such approval.

Our Managing Member will not have any liability to us or our unitholders for decisions whether or not to seek the approval of the conflicts committee of the board of directors of the Managing Member or holders of a majority of ENLC common units, excluding any ENLC common units owned by the Managing Member and its affiliates. If an affiliate transaction or the resolution of a conflict of interest is not approved by the conflicts committee or holders of ENLC common units, then it will be presumed that, in making its decision, taking any action or failing to act, the board of directors acted in good faith, and in any proceeding brought by or on behalf of any member or us, the person bringing or prosecuting such proceeding will have the burden of overcoming such presumption.

Holders of ENLC common units have limited voting rights and are not entitled to elect the Managing Member or the board of directors of the Managing Member, which could reduce the price at which ENLC common units trade.

Unlike the holders of common stock in a corporation, ENLC unitholders have only limited voting rights on matters affecting our business and, therefore, limited ability to influence management's decisions regarding our business. Unitholders do not have the right to elect the Managing Member or the board of directors of the Managing Member on an annual or other continuing basis. The board of directors of the Managing Member, including its independent directors, is chosen by the sole member of the Managing Member. Furthermore, if unitholders are dissatisfied with the performance of the Managing Member, they will have very limited ability to remove the Managing Member. Our operating agreement also contains provisions limiting the ability of unitholders to call meetings or to acquire information about our operations, as well as other provisions limiting the unitholders' ability to influence the manner or direction of management. As a result of these limitations, the price at which ENLC common units trade could be diminished because of the absence or reduction of a takeover premium in the trading price.

Even if our unitholders are dissatisfied, they cannot initially remove the Managing Member without its consent.

ENLC's unitholders are unable to remove the Managing Member without its consent because the Managing Member and its affiliates own sufficient units to be able to prevent its removal. The vote of the holders of at least 66 2/3% of all outstanding ENLC common units voting together as a single class is required to remove the Managing Member. As of February 11, 2021, the Managing Member and its affiliates owned approximately 45.8% of the outstanding ENLC common units.

GIP has pledged all of the equity interests that it owns in ENLC and the 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 the Managing Member.

GIP has pledged all of the equity interests that it owns in ENLC and the 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 the Managing Member and would allow the new owner to replace the board of directors and officers of the Managing Member with its own designees and to control the decisions taken by the board of directors and officers. Moreover, any change of control of the Managing Member would permit the lenders under ENLC's Consolidated Credit Facility, the Term Loan, and AR Facility to declare all amounts thereunder immediately due and payable, and if any such event occurs, we may be required to refinance our debt on unfavorable terms, which could negatively impact our results of operations and our ability to make distributions to our unitholders.

Our operating agreement restricts the voting rights of unitholders owning 20% or more of ENLC's common units.

Unitholders' voting rights are further restricted by our operating agreement, which provides that any units held by a person that owns 20% or more of any class of units, other than the Managing Member, its affiliates, their transferees and persons who acquired such units with the prior approval of the board of directors of the Managing Member, including the holders of the ENLC Class C Common Units, cannot vote on any matter.

The control of the Managing Member may be transferred to a third party without unitholder consent.

Our Managing Member may transfer its managing member 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, our operating agreement does not restrict the ability of GIP to transfer all or a portion of the ownership interest in the Managing Member to a third party. If the managing member interest were transferred, the new owner of the Managing Member would then be in a position to replace the board of directors and officers of the Managing Member with its own choices and thereby exert significant control over the decisions made by such board of directors and officers. This effectively permits a "change of control" of the Managing Member without the vote or consent of the unitholders. On July 18, 2018, Devon sold its equity interests in us and our Managing Member to affiliates of GIP. For more information about the GIP Transaction, see "Item 8. Financial Statements and Supplementary Data—Note 1."

We may issue additional units, including units that are senior to ENLC common units, without the approval of the holders of common units, which would dilute existing ownership interests.

Our operating agreement does not limit the number of additional membership interests that we may issue at any time without the approval of our unitholders, except that our operating agreement restricts our ability to issue any membership interests senior to or on parity with the Series B Preferred Units with respect to distributions on such membership interests or upon liquidation without the affirmative vote of the holders of a majority of our outstanding ENLC Class C Common Units, voting separately as a class. The issuance by us of additional ENLC common units or other equity securities of equal or senior rank will have the following effects:

- each unitholder's proportionate ownership interest in us will decrease;
- the amount of cash available for distribution on each unit may decrease;
- the relative voting strength of each previously outstanding unit may be diminished; and
- the market price of ENLC common units may decline.

The ENLC Class C Common Units give the holders thereof certain rights relating to our business and management, and the ability to exchange such holder's Series B Preferred Units into our common units, which could cause dilution to our common unitholders.

Immediately following the closing of the Merger, ENLC issued to Enfield 58,728,994 ENLC Class C Common Units in order to provide Enfield with certain voting rights at ENLC in accordance with our operating agreement. Following the Merger, for each additional Series B Preferred Unit issued by ENLK pursuant to its partnership agreement, ENLC will issue an additional Class C Common Unit to the applicable holder of Series B Preferred Units, so that the number of ENLC Class C Common Units issued and outstanding will always equal the number of Series B Preferred Units issued and outstanding. In connection with the issuance of the ENLC Class C Common Units, ENLC, the Managing Member, and GIP III Stetson I, L.P. entered into a board representation agreement with TPG VII Management, LLC, an affiliate of Enfield ("TPG Management"), pursuant to which TPG Management is entitled to appoint one director to the Manager Board, subject to certain conditions and limitations. In addition, the holders of ENLC Class C Common Units will vote with the holders of common units as a single class on all matters on which holders of common units are entitled to vote. Each Class C Common Unit will be entitled to the number of votes equal to the number of common units into which a Series B Preferred Unit is then exchangeable, which is the product of the number of Series B Preferred Units being exchanged multiplied by 1.15 (subject to certain adjustments).

In addition, the holders of Class C Common Units are entitled to vote as a separate class on any matter that (i) adversely affects the rights, preferences, and privileges of the ENLC Class C Common Units or the Series B Preferred Units, including certain leverage ratio restrictions and other minority protections with respect to substantially the same matters for which the holders of Series B Preferred Units have approval rights under the ENLK partnership agreement, or (ii) amends or modifies any of the terms of the ENLC Class C Common Units or Series B Preferred Units. The approval of a majority of the ENLC Class C Common Units is required to approve any matter for which the holders of ENLC Class C Common Units are entitled to vote as a separate class. These restrictions may adversely affect our ability to finance future operations or capital needs or to engage in other business activities.

Furthermore, the exchange of the Series B Preferred Units into common units, which Enfield may elect to cause at any time, may cause substantial dilution to the holders of the common units. As of February 11, 2021, on an as-exchanged basis, the Series B Preferred Units (and the corresponding voting power of the ENLC Class C Common Units) represented approximately 11.0% of the membership interests of ENLC.

GIP may sell ENLC common units in the public markets or otherwise, which sales could have an adverse impact on the trading price of our common units.

As of February 11, 2021, GIP held 224,355,359 ENLC common units. Additionally, we have agreed to provide GIP with certain registration rights with respect to the ENLC common units held by it. The sale of these units could have an adverse impact on the price of ENLC common units or on any trading market that may develop.

Our Managing Member has a call right that may require unitholders to sell their ENLC common units at an undesirable time or price.

If at any time the Managing Member and its affiliates own more than 90% of ENLC's common units, the Managing Member will have the right, but not the obligation, which it may assign to any of its affiliates or to us, to acquire all, but not less than all, of ENLC common units held by unaffiliated persons at a price equal to the greater of (1) the average of the daily closing price of ENLC common units over the 20 trading days preceding the date three days before notice of exercise of the call right is first mailed and (2) the highest per-unit price paid by the Managing Member or any of its affiliates for ENLC common units during the 90-day period preceding the date such notice is first mailed. As a result, unitholders may be required to sell their ENLC common units at an undesirable time or price and may not receive any return or a negative return on their investment. Unitholders may also incur a tax liability upon a sale of their units. Our Managing Member is not obligated to obtain a fairness opinion regarding the value of ENLC common units to be repurchased by it upon exercise of the call right. There is no restriction in our operating agreement that prevents the Managing Member from issuing additional ENLC common units and exercising its call right. If the Managing Member exercised its call right, the effect would be to take us private. As of February 11, 2021, GIP owned an aggregate of approximately 45.8% of outstanding ENLC common units.

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 the DLLCA, a limited liability company may not make a distribution to a member if, after the distribution, all liabilities of the limited liability company, other than liabilities to members on account of their membership interests and liabilities for which the recourse of creditors is limited to specific property of the company, would exceed the fair value of the assets of the limited liability company. For the purpose of determining the fair value of the assets of a limited liability company, the DLLCA 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 liability company only to the extent that the fair value of that property exceeds the non-recourse liability. The DLLCA provides that a member who receives a distribution and knew at the time of the distribution that the distribution was in violation of the DLLCA will be liable to the limited liability company for the amount of the distribution for three years following the date of the distribution.

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

As of February 11, 2021, approximately 54.1% of ENLC common units were held by public unitholders. The lack of liquidity may result in wide bid-ask spreads, contribute to significant fluctuations in the market price of ENLC common units, and limit the number of investors who are able to buy ENLC common units. The market price of ENLC common units may be influenced by many factors, some of which are beyond our control, including:

- the quarterly distributions paid by us with respect to ENLC common units;
- our quarterly or annual earnings, or those of other companies in our industry;
- the loss of Devon as a customer;
- events affecting Devon;
- events affecting GIP;
- announcements by us or our competitors of significant contracts or acquisitions;
- changes in accounting standards, policies, guidance, interpretations, or principles;
- general economic conditions;
- the failure of securities analysts to cover ENLC common units or changes in financial estimates by analysts;
- future sales of ENLC common units; and
- other factors described in these "Risk Factors."

We are a "controlled company" within the meaning of NYSE rules and, as a result, we qualify for, and rely on, exemptions from some of the listing requirements with respect to independent directors.

Because GIP controls more than 50% of the voting power for the election of directors of the Managing Member, we are a controlled company within the meaning of NYSE rules, which exempt controlled companies from the following corporate governance requirements:

- the requirement that a majority of the board consist of independent directors;

- the requirement that the board of directors have a nominating or corporate governance committee, composed entirely of independent directors, that is responsible for identifying individuals qualified to become board members, consistent with criteria approved by the board, selection of board nominees for the next annual meeting of equity holders, development of corporate governance guidelines and oversight of the evaluation of the board and management;

- the requirement that we have a compensation committee of the board, composed entirely of independent directors, that is responsible for reviewing and approving corporate goals and objectives relevant to chief executive officer compensation, evaluation of the chief executive officer's performance in light of the goals and objectives, determination and approval of the chief executive officer's compensation, making recommendations to the board with respect to compensation of other executive officers and incentive compensation and equity-based plans that are subject to board approval and producing a report on executive compensation to be included in an annual proxy statement or Form 10-K filed with the Commission;

- the requirement that we conduct an annual performance evaluation of the nominating, corporate governance and compensation committees; and

- the requirement that we have written charters for the nominating, corporate governance and compensation committees addressing the committees' responsibilities and annual performance evaluations.

For so long as we remain a controlled company, we will not be required to have a majority of independent directors or nominating, corporate governance or compensation committees composed entirely of independent directors. Accordingly, you may not have the same protections afforded to stockholders of companies that are subject to all of the NYSE corporate governance requirements.

Financial and Indebtedness Risks

Our cash flow consists almost exclusively of cash flows from ENLK.

Currently, our only cash-generating asset is our partnership interest in ENLK. Our cash flow is therefore completely dependent upon the ability of ENLK to generate cash or our ability to borrow under the Consolidated Credit Facility and the AR Facility.

The amount of cash that ENLK can provide to us each quarter principally depends upon the amount of cash it generates from its operations, which will fluctuate from quarter to quarter based on, among other things:

- the level of ENLK's processing operations;
- the fees ENLK charges and the margins it realizes for its services;
- the prices of, levels of production of, and demand for crude oil, condensate, NGLs, and natural gas;
- the volume of natural gas ENLK gathers, compresses, processes, transports, and sells, the volume of NGLs ENLK processes or fractionates and sells, the volume of crude oil ENLK handles at its crude terminals, the volume of crude oil and condensate that ENLK gathers, transports, purchases, and sells, the volumes of condensate stabilized, and the volumes of brine ENLK disposes;
- the relationship between natural gas and NGL prices; and
- ENLK's level of operating costs.

In addition, the actual amount of cash generated by ENLK that will be available to us will depend on other factors, some of which are beyond its control, including:

- the level of capital expenditures ENLK makes;
- the cost of acquisitions, if any;

- ENLK's debt service requirements and distribution requirements with respect to Series B Preferred Units and Series C Preferred Units;
- fluctuations in its working capital needs;
- prevailing economic conditions; and
- the amount of cash reserves established by the General Partner in its sole discretion for the proper conduct of business.

Because of these and potentially other factors, we may not be able, or may not have sufficient available cash to pay distributions to unitholders each quarter. Furthermore, you should also be aware that the amount of cash ENLK has available depends primarily upon its cash flows, including cash flow from financial reserves and working capital borrowings, and is not solely a function of profitability, which will be affected by non-cash items. As a result, ENLK may make cash distributions during periods when it records losses and may not make cash distributions during periods when it records net income.

The terms of the Consolidated Credit Facility, the Term Loan, the AR Facility, and indentures governing our senior notes and ENLK's senior 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, the AR Facility, and the indentures governing our senior notes and ENLK's senior notes contain, and any future indebtedness we incur will likely contain, a number of restrictive covenants that impose significant operating and financial restrictions, including restrictions on our ability to engage in acts that may be in our best long-term interest. One or more of these agreements include covenants that, among other things, restrict our ability to:

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

In addition, the Consolidated Credit Facility and the Term Loan require us to satisfy and maintain specified financial ratios, and the AR Facility requires ENLC's consolidated leverage ratio not to exceed limits identical to those in the Consolidated Credit Facility and the Term Loan. The AR Facility also contains events of default relating to a borrowing base deficiency and events negatively affecting the overall credit quality of the receivables securing the AR Facility. Our ability to meet those financial ratios and receivables-related tests can be affected by events beyond our control, including prevailing economic, financial, and industry conditions, and we cannot assure you that we will meet those ratios and receivables-related tests, particularly if market or other economic conditions deteriorate.

A breach of any of these covenants could result in an event of default under the applicable debt agreement. 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 applicable debt agreements 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 debt agreements may adversely affect our ability to finance future operations or capital needs or to engage in other business activities.

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, future business opportunities, and distributions to unitholders will be reduced by that portion of our cash flows required to make interest payments on our debt;
- our debt level will make us more vulnerable to general adverse economic and industry conditions;
- our ability to plan for, or react to, changes in our business and the industry in which we operate; and
- our risk that we may default on our debt obligations.

In addition, our ability to make scheduled payments or to refinance our obligations depends on our successful financial and operating performance, which will be affected by prevailing economic, financial, and industry conditions, many of which are beyond our control. If our cash flow and capital resources are insufficient to fund our debt service obligations, we may be forced to take actions such as further 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.

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. As of February 11, 2021, Fitch Ratings, S&P, and Moody's have assigned a BB+, BB+, and Ba2 credit rating, respectively, to ENLK and ENLC. 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.

An impairment of long-lived assets, including intangible assets, equity method investments, and right-of-use assets related to leases could reduce our earnings.

GAAP requires us to test long-lived assets, including intangible assets with finite useful lives, for impairment whenever events or changes in circumstances indicate that the carrying amount may not be recoverable. For the investments we account for under the equity method, the impairment test considers whether the fair value of the unconsolidated affiliate investment as a whole, not the underlying net assets, has declined and whether that decline is other than temporary. If we determine that an impairment is indicated, we would be required to take an immediate non-cash charge to earnings with a correlative effect on equity and balance sheet leverage as measured by debt to total capitalization. For the year ended December 31, 2020, we recognized impairment expense related to goodwill; property and equipment, including cancelled projects; and lease right-of-use assets. Impairment expense is composed of the following amounts (in millions):

	Year Ended December 31, 2020
Goodwill impairment (1)	$ 184.6
Property and equipment impairment (2)	168.0
Lease right-of-use asset impairment (3)	6.8
Cancelled projects (2)	3.4
Total impairments	$ 362.8

(1) For additional information see "Item 8. Financial Statements and Supplementary Data—Note 3."
(2) For additional information see "Item 8. Financial Statements and Supplementary Data—Note 2."
(3) For additional information see "Item 8. Financial Statements and Supplementary Data—Note 5."

We have recognized goodwill impairments and impairments on property and equipment in the past. See "Item 8. Financial Statements and Supplementary Data—Note 2" for more information about impairment of goodwill and long-lived assets. Additional impairment of the value of our existing long-lived assets could have a significant negative impact on our future operating results.

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 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."

Increases in interest rates could adversely impact the price of ENLC's common units, ENLC's or ENLK's ability to issue equity or incur debt for acquisitions or other purposes, and ENLC's or ENLK's ability to make cash distributions.

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

We may not realize our deferred tax assets.

As of December 31, 2020, we had deferred tax assets (primarily consisting of net operating loss carryovers) of $549.3 million, against which we provided a valuation allowance of $153.3 million. The ultimate realization of our deferred tax assets is dependent upon generating future taxable income to utilize our net operating loss carryovers before they expire. While we have recorded valuation allowances against certain of our deferred tax assets, the valuation allowances are subject to change as facts and circumstances change.

Additionally, Section 382 of the Internal Revenue Code of 1986, as amended ("Section 382"), generally imposes an annual limitation on the amount of net operating losses and other pre-change tax attributes (such as tax credits) that may be used to offset taxable income by a corporation that has undergone an "ownership change" (as determined under Section 382). An ownership change generally occurs if one or more shareholders (or groups of shareholders) that are each deemed to own at least 5% of our stock increase their ownership by more than 50 percentage points over their lowest ownership percentage during a rolling three-year period. As of December 31, 2020, we have not experienced an ownership change. Therefore, our utilization of net operating loss carryforwards was not subject to an annual limitation. However, if we were to experience ownership changes in the future as a result of subsequent shifts in our common unit ownership, our ability to use our pre-change net operating loss carryforwards to offset future taxable income may be subject to limitations, which could potentially result in increased future tax liability to us. Additionally, at the state level, there may be periods during which the use of NOL carryforwards is suspended or otherwise limited, which could accelerate or permanently increase state taxes owed. In any case, our net operating loss and tax credit carryforwards are subject to review and potential disallowance upon audit by the tax authorities of the jurisdictions where these tax attributes are incurred.

The value of our deferred tax assets and liabilities are also dependent upon the tax rates expected to be in effect at the time they are realized. A change in enacted corporate tax rates in our major jurisdictions, especially the U.S. federal corporate tax rate, would change the value of our deferred taxes, which could be material.

We are treated as a corporation subject to entity level federal and state income taxation. Any such entity level income taxes will reduce the amount of cash available for distribution to you.

We are treated as a corporation for tax purposes that is required to pay federal and state income tax on our taxable income at corporate rates. Historically, we have had net operating losses ("NOLs") that eliminated substantially all of our taxable income and, thus, we historically have not had to pay material amounts of income taxes. We anticipate generating NOLs for tax purposes during 2021, and as a result, do not expect to incur material amounts of federal and state income tax liabilities. In the event we do generate taxable income, federal and state income tax liabilities will reduce the cash available for distribution to our unitholders.

Tax legislation was enacted during 2017 which, among other things, (i) reduced the U.S. corporate income tax rate from 35% to 21%, (ii) generally limits our annual deductions for interest expense to no more than 30% of our "adjusted taxable income" (plus 100% of our business interest income) for the year, (iii) permits us to offset only 80% (rather than 100%) of our taxable income with any NOLs we generate after 2017, and (iv) eliminated the deduction for certain domestic production activities. Currently we do not expect the provisions of the 2017 tax legislation, taken as a whole, to have any material adverse impact on our cash tax liabilities, financial condition, results of operations, or cash flows. However, it is possible in the future that the NOL and/or interest deductibility limitations could have the effect of causing us to incur income tax liability sooner than we otherwise would have incurred such liability or, in certain cases, could cause us to incur income tax liability that we might otherwise not have incurred, in the absence of these tax law changes.

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, the Term Loan, and the AR Facility currently bear interest at rates based on the U.S. Dollar London Interbank Offered Rate ("LIBOR"). 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. On November 30, 2020, ICE Benchmark Administration, the current administrator of LIBOR, announced that it intends to cease publication of 1-week and 2-month LIBOR at the end of 2021 and, subject to compliance with applicable regulations, including as to representativeness, it does not intend to cease publication of the remaining tenors until June 30, 2023. It is uncertain whether USD LIBOR will be available as a benchmark for pricing our floating rate indebtedness until, or after, June 30, 2023. The Consolidated Credit Facility, the Term Loan, and the AR Facility include mechanisms 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, the Term Loan, and the AR Facility 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.

Business and Industry Risks

The ongoing coronavirus (COVID-19) pandemic has adversely affected and could continue to adversely affect our business, financial condition, and results of operations.

On March 11, 2020, the World Health Organization declared the ongoing coronavirus (COVID-19) outbreak a pandemic and recommended containment and mitigation measures worldwide. The ongoing pandemic has reached every region of the globe and has resulted in widespread adverse impacts on the global economy, on the energy industry as a whole and on midstream companies, and on our customers, suppliers, and other parties with whom we have business relations. The pandemic and related travel and operational restrictions, as well as business closures and curtailed consumer activity, have resulted in a reduction in global demand for energy, volatility in the market prices for crude oil, condensate, natural gas, and NGLs, and a significant reduction in the market price of crude oil during the first and second quarter of 2020. As a result of the demand destruction, reduced commodity prices, and an uncertain timeline for full recovery, many oil and natural gas producers, including some of our customers, curtailed their current drilling and production activity and reduced or slowed down their plans for future drilling and production activity. As a result of these decreases in producer activity, we experienced reduced volumes gathered, processed, fractionated, and transported on our assets in some of the regions that supply our systems during portions of the first and second quarters of 2020, and capital investments by oil and natural gas producers remain at low levels.

Since the outbreak began, our first priority has been the health and safety of our employees and those of our customers and other business counterparties. In March, we implemented preventative measures and developed a response plan to minimize unnecessary risk of exposure and prevent infection, while supporting our customers' operations, and we continue to follow these plans. We maintain a crisis management team for health, safety and environmental matters and personnel issues and a cross-functional COVID-19 response team to address various impacts of the situation, as they develop. We also continue to follow modified business practices (including discontinuing non-essential business travel, implementing work-from-home policies, during high-transmission period, and staggered work-from-home policies for employees who can execute their work remotely in order to reduce office density, and encouraging employees to adhere to local and regional social distancing recommendations) to support efforts to reduce the spread of COVID-19 and to conform to government restrictions and best practices encouraged by the Centers for Disease Control and Prevention, the World Health Organization, and other governmental and regulatory authorities. We also have promoted heightened awareness and vigilance, hygiene, and implementation of more stringent cleaning protocols across our facilities and operations. We continue to evaluate and adjust these preventative measures, response plans and business practices with the evolving impacts of COVID-19. However, the quarantine of personnel or the inability to access our facilities or customer sites could adversely affect our operations. Also, we have a limited number of highly skilled employees for some of our operations. If a large proportion of our employees in those critical positions were to contract COVID-19 at the same time, we would rely upon our business continuity plans in an effort to continue operations at our systems, pipelines, and facilities, but there is no certainty that such measures will be sufficient to mitigate the adverse impact to our operations that could result from shortages of highly skilled employees.

There is considerable uncertainty regarding how long the COVID-19 pandemic will persist and affect economic conditions and the extent and duration of changes in consumer behavior, such as the reluctance to travel, as well as whether governmental and other measures implemented to try to slow the spread of the virus, such as large-scale travel bans and restrictions, border closures, quarantines, shelter-in-place orders, and business and government shutdowns that exist as of the date of this report will be extended or whether new measures will be imposed. As a result, there is significant uncertainty regarding whether market dislocations will continue or increase and how significantly and how long they may affect us. We expect to see continued volatility in crude oil, condensate, natural gas, and NGL prices for the foreseeable future, which may, over the long term, adversely impact our business. A sustained significant decline in oil and natural gas exploration and production activities and related reduced demand for our services by our customers, whether due to decreases in consumer demand or reduction in the prices for oil, condensate natural gas and NGLs or otherwise, would have a material adverse effect on our business, liquidity, financial condition, results of operations, and cash flows.

These uncertain economic conditions may also result in the inability of our customers and other counterparties to make payments to us, on a timely basis or at all, which could adversely affect our business, liquidity, financial condition, results of operations, and cash flows. A substantial deterioration in our business and/or a prolonged period of market dislocation could also affect our compliance with the financial covenants in our revolving credit facility, particularly the consolidated leverage ratio covenant. If we were unable to continue to meet any of the financial covenants, we would not be able to borrow funds under our revolving credit facility and we would not be able to use the revolving credit facility to refinance the remaining $350 million on the Term Loan in 2021.

We cannot predict the full impact that the COVID-19 pandemic or the volatility in oil and natural gas markets related to COVID-19 will have on our business, liquidity, financial condition, results of operations, and cash flows at this time due to numerous uncertainties. Furthermore, the COVID-19 pandemic (including federal, state and local governmental responses, broad economic impacts and market disruptions) has heightened a number of the risks discussed in the risk factors described in this report. The ultimate impacts will depend on future developments, including, among others, the ultimate duration and persistence of the pandemic, the speed at which the population is vaccinated against the virus and the efficacy of the vaccines, the effect of the outbreak on economic, social and other aspects of everyday life, the consequences of governmental and other measures designed to prevent the spread of the virus, actions taken by members of OPEC+ and other foreign, oil-exporting countries, actions taken by governmental authorities, customers, suppliers, and other third parties, and the timing and extent to which normal economic, social and operating conditions resume.

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 MVCfrom 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 2020 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, 2020, Devon represented approximately 30.6% of our adjusted gross margin. For the period following Devon’s sale of its Barnett Shale assets to BKV in October 2020 through December 31, 2020, Devon represented approximately 26.5% of our adjusted gross 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 expired in December 2020. In 2021, if volumes gathered, processed, and transported for Devon do not increase or we are unable to replace the shortfall revenue from other sources, our operating results and cash flows will be adversely affected.

Because we are substantially dependent on Devon for a significant portion of our adjusted gross 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 adjusted gross 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.

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.

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.

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.

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.

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, 2020, approximately 5% of our total adjusted gross 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. Adjusted gross 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 adjusted gross margins under processing margin contracts. For the year ended December 31, 2020, less than 1% of our total adjusted gross 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, 2020, adjusted gross margin realized associated with product upgrades represented less than 1% of our adjusted gross margin.

Commodity prices were volatile during 2020. Crude oil prices decreased 21% while weighted average NGL prices and natural gas prices each increased 20% from January 1, 2020 to December 31, 2020. We expect continued volatility in these commodity prices. For example, see the table below for the range of closing prices for crude oil, NGL, and natural gas during 2020.

Commodity	**Closing Price**		**Date**
Crude oil (high) (1)	$	63.27	January 6, 2020
Crude oil (low) (1)	$	(37.63)	April 20, 2020
Crude oil (average) (1)(4)	$	39.28	Not applicable
NGL (high) (2)	$	0.48	December 31, 2020
NGL (low) (2)	$	0.10	March 23, 2020
NGL (average) (2)(4)	$	0.31	Not applicable
Natural gas (high) (3)	$	3.35	October 30, 2020
Natural gas (low) (3)	$	1.48	June 25, 2020
Natural gas (average) (3)(4)	$	2.13	Not applicable

(1) Crude oil closing prices based on the NYMEX futures daily close prices.
(2) Weighted average NGL gas closing prices based on the Oil Price Information Service Napoleonville daily average spot liquids prices.
(3) Natural gas closing prices based on Gas Daily Henry Hub closing prices.
(4) The average closing price was computed by taking the sum of the closing prices of each trading day divided by the number of trading days during the period presented.

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 adjusted gross 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.

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.

Increasing scrutiny and changing expectations from stakeholders with respect to our environmental, social and governance practices may impose additional costs on us or expose us to new or additional risks.

Companies across all industries are facing increasing scrutiny from stakeholders related to their environmental, social, and governance ("ESG") practices. Investor advocacy groups, certain institutional investors, investment funds, and other influential investors are also increasingly focused on ESG practices and in recent years have placed increasing importance on the implications and social cost of their investments. Regardless of the industry, investors' increased focus and activism related to ESG and similar matters may hinder access to capital, as investors may decide to reallocate capital or to not commit capital as a result of their assessment of a company's ESG practices. Companies that do not adapt to or comply with investor or stakeholder expectations and standards, which are evolving, or which are perceived to have not responded appropriately to the growing concern for ESG issues, regardless of whether there is a legal requirement to do so, may suffer from reputational damage and the business, financial condition, and/or stock price of such a company could be materially and adversely affected.

We face pressures from our stakeholders, who are increasingly focused on climate change, to prioritize sustainable energy practices, reduce our carbon footprint and promote sustainability. Our stakeholders may require us to implement ESG procedures or standards in order to remain invested in us or before they may make further investments in us. Additionally, we may face reputational challenges in the event our ESG procedures or standards do not meet the standards set by certain constituencies. We have adopted certain practices as highlighted in our annual sustainability report, including commitments to environmental stewardship by operating our assets and constructing new facilities in order to minimize our footprint and environmental impact, control pollution and conserve resources. It is possible, however, that our stakeholders might not be satisfied with our sustainability efforts or the speed of their adoption. If we do not meet our stakeholders' expectations, our business, ability to access capital, and/or our common unit price could be harmed.

Additionally, adverse effects upon the oil and gas industry related to the worldwide social and political environment, including uncertainty or instability resulting from climate change, changes in political leadership and environmental policies, changes in geopolitical-social views toward fossil fuels and renewable energy, concern about the environmental impact of climate change and investors' expectations regarding ESG matters, may also adversely affect demand for our services. Any long-term material adverse effect on the oil and gas industry could have a significant financial and operational adverse impact on our business.

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 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.

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.

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.

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 adjusted gross 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, it will adversely affect our financial condition, results of operations, or cash flows.

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, ice storms, blizzards, 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, ice storms, 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.

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 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.

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, the Term Loan, and the AR Facility 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, 2020, 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.

Environmental, Legal Compliance, and Regulatory Risks

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 September 2020, the EPA published two rules removing sources in the transmission and storage segments from the regulated source category and rescinding the application of the NSPS and methane-specific requirements to these sources. EPA’s September 2020 rules are being challenged in the U.S. Circuit Court for the D.C. Circuit. 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. In July 2020, the U.S. District Court for the Northern District of California vacated BLM’s 2018 revision rule. Additionally, in October 2020, a Wyoming federal district judge vacated the 2016 venting and flaring rule.

In addition, President Biden has declared that he 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. On January 20, 2021, the Acting Secretary for the Department of the Interior signed an order suspending new fossil fuel leasing and permitting on federal lands for 60 days, which may cover our offshore pipeline permits. If our customers are unable to secure permits, sustained reductions in exploration or production activity in our areas of operation could lead to reduced utilization of our pipeline and terminal systems or reduced rates under renegotiated transportation or storage agreements. We are still evaluating the effects of the recent order on our operations and our customers' operations, but our inability and our customers' inability to secure required permits could adversely affect our business, financial condition, results of operation or cash flows, including our ability to make cash distributions to our unitholders. The Biden 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 and withdrew from the agreement in November 2020. However, on January 20, 2021, President Biden signed an instrument that reverses this withdrawal, and the United States will formally re-join the Paris Agreement on February 19, 2021. 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. Additionally, President Biden has issued an executive order seeking to adopt new regulations and policies to address climate change and suspend, revise or rescind prior agency actions that are identified as conflicting with the Biden Administration's climate policies.

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 President Biden during his U.S. presidential campaign. President Biden has declared that he would support federal government efforts to limit or prohibit hydraulic fracturing and banning new leases for production of minerals on federal properties, including onshore lands and offshore waters. The Biden 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.

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.

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, effective in December 2019, 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, effective in July 2020, 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 $2.6 million, $3.1 million, and $1.8 million for the years ended December 31, 2020, 2019, and 2018, 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 VOCs from new and modified sources in the oil and gas sector. In September 2020, the EPA published two additional final rules that removed sources in the transmission and storage segment from the regulated source category of the 2016 NSPS, rescinded the NSPS (including both VOC and methane requirements) applicable to those sources, and rescinded the methane-specific requirements of the NSPS applicable to sources in the production and processing segments. EPA's September 2020 rules are being challenged in the U.S. Circuit Court for the D.C. Circuit. 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, 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. In July 2020, the U.S. District Court for the Northern District of California vacated BLM's 2018 revision rule. Additionally, in October 2020, a Wyoming federal district judge vacated the 2016 venting and flaring rule.

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.

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 had previously issued several relevant regulations, 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. On October 15, 2020, the CFTC voted to adopt a final rule amending previously issued regulations to conform with certain Dodd-Frank amendments to the Commodity Exchange Act. Among other things, the Commission adopted new and amended federal spot month position limits for derivatives contracts associated with certain physical commodities.

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 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.

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 Managing Member 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.

See "Item 8. Financial Statements and Supplementary Data—Note 14" for more information on litigation contingencies.

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, Related Unitholder Matters, and Issuer Purchases of Equity Securities

Our common units are listed on the NYSE under the symbol "ENLC." On December 11, 2020, there were approximately 29,281 record holders and beneficial owners (held in street name) of ENLC 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."

Unless restricted by the terms of the Consolidated Credit Facility or the Term Loan, we intend to pay distributions to our unitholders on a quarterly basis from our available cash less reserves for expenses, future distributions, and other uses of cash, including:

- provisions for the proper conduct of our business;
- paying federal income taxes, which we are required to pay because we are taxed as a corporation; and
- maintaining cash reserves the board of directors of the Managing Member believes are prudent to maintain.

Unregistered Sales of Equity Securities and Use of Proceeds

During the three months ended December 31, 2020, we re-acquired ENLC common units from certain employees in order to satisfy the employees' tax liability in connection with the vesting of restricted incentive units, and we repurchased common units in open market transactions in connection with a common unit repurchase program.

Period	Total Number of Units Purchased (1)	Average Price Paid Per Unit	Total Number of Units Purchased as Part of Publicly Announced Plans or Programs (2)	Maximum Dollar Value of Units that May Yet Be Purchased under the Plans or Programs (in millions) (2)
October 1, 2020 to October 31, 2020	3,809	$ 2.33	—	$ —
November 1, 2020 to November 30, 2020	390,421	$ 3.01	383,614	$ 98.8
December 1, 2020 to December 31, 2020	—	$ —	—	$ 98.8
Total	394,230	$ 3.00	383,614	

(1) These common units were not re-acquired pursuant to any repurchase plan or program.

(2) On November 4, 2020, we announced a $100.0 million common unit repurchase program. During 2020, we repurchased 383,614 common units for an aggregate price of $1.2 million, or an average of $3.00 per common unit. Future repurchases under the program may be made from time to time in open market or private transactions and may be made pursuant to a trading plan meeting the requirements of Rule 10b5-1 under the Securities Exchange Act of 1934, as amended. The repurchases will depend on market conditions and may be discontinued at any time.

Item 6. Selected Financial Data

The following tables present our selected historical financial and operating data of ENLC for the periods indicated. Financial and operating data for the years ended December 31, 2020, 2019, 2018, 2017, and 2016 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."

	ENLC Year Ended December 31,				
	2020	2019	2018	2017	2016
	(In millions, except per unit data)				
Revenues:					
Product sales	$ 2,977.5	$ 5,030.1	$ 6,512.3	$ 4,358.4	$ 3,008.9
Product sales—related parties	—	—	41.0	144.9	134.3
Midstream services	938.3	1,008.4	763.3	552.3	467.2
Midstream services—related parties	—	—	377.2	688.2	653.1
Gain (loss) on derivative activity	(22.0)	14.4	5.2	(4.2)	(11.1)
Total revenues	3,893.8	6,052.9	7,699.0	5,739.6	4,252.4
Operating costs and expenses:					
Cost of sales, exclusive of operating expenses and depreciation and amortization (1)	2,388.5	4,392.5	6,008.0	4,361.5	3,015.5
Operating expenses	373.8	467.1	453.4	418.7	398.5
Depreciation and amortization	638.6	617.0	577.3	545.3	503.9
Impairments	362.8	1,133.5	365.8	17.1	873.3
(Gain) loss on disposition of assets	8.8	(1.9)	0.4	—	13.2
General and administrative	103.3	152.6	140.3	128.6	122.5
Loss on secured term loan receivable	—	52.9	—	—	—
Gain on litigation settlement	—	—	—	(26.0)	—
Total operating costs and expenses	3,875.8	6,813.7	7,545.2	5,445.2	4,926.9
Operating income (loss)	18.0	(760.8)	153.8	294.4	(674.5)
Other income (expense):					
Interest expense, net of interest income	(223.3)	(216.0)	(182.3)	(190.4)	(189.5)
Gain on extinguishment of debt	32.0	—	—	9.0	—
Income (loss) from unconsolidated affiliates	0.6	(16.8)	13.3	9.6	(19.9)
Other income	0.3	0.9	0.6	0.6	0.3
Total other expense	(190.4)	(231.9)	(168.4)	(171.2)	(209.1)
Income (loss) before non-controlling interest and income taxes	(172.4)	(992.7)	(14.6)	123.2	(883.6)
Income tax benefit (expense)	(143.2)	(6.9)	(18.2)	196.8	(4.6)
Net income (loss)	(315.6)	(999.6)	(32.8)	320.0	(888.2)
Net income (loss) attributable to non-controlling interests	105.9	119.7	(19.6)	107.2	(428.2)
Net income (loss) attributable to ENLC	$ (421.5)	$ (1,119.3)	$ (13.2)	$ 212.8	$ (460.0)
Net income (loss) attributable to ENLC per unit:					
Basic common unit	$ (0.86)	$ (2.41)	$ (0.07)	$ 1.18	$ (2.56)
Diluted common unit	$ (0.86)	$ (2.41)	$ (0.07)	$ 1.17	$ (2.56)
Distributions declared per common unit	$ 0.3750	$ 1.0325	$ 1.076	$ 1.024	$ 1.020

(1) Includes related party cost of sales of $8.7 million, $21.7 million, $114.1 million, $211.0 million, and $150.1 million for the years ended December 31, 2020, 2019, 2018, 2017, and 2016, respectively. Excludes all operating expenses as well as depreciation and amortization related to our operating segments of $631.3 million, $608.6 million, $568.6 million, $535.4 million, and 494.7 million for the years ended December 31, 2020, 2019, 2018, 2017, and 2016, respectively.

	ENLC December 31,				
	2020	2019	2018	2017	2016
	(In millions)				
Balance Sheet Data (end of period):					
Property and equipment, net	$ 6,652.1	$ 7,081.3	$ 6,846.7	$ 6,587.0	$ 6,256.7
Total assets	8,550.9	9,335.8	10,694.1	10,537.8	10,275.9
Long-term debt (including current maturities)	4,593.8	4,764.3	4,430.8	3,542.1	3,295.3
Members' equity including non-controlling interest	3,213.0	3,806.1	4,974.2	5,556.7	5,265.6

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, 2018 and year-to-year comparisons of the year ended December 31, 2019 and the year ended December 31, 2018 can be found in "Management's Discussion and Analysis of Financial Condition and Results of Operations" in Part II, Item 7 of ENLC's Annual Report on Form 10-K for the year ended December 31, 2019.

In this report, the terms "Company" or "Registrant," as well as the terms "ENLC," "our," "we," "us," or like terms, are sometimes used as abbreviated references to EnLink Midstream, LLC itself or EnLink Midstream, LLC together with its consolidated subsidiaries, including ENLK and its consolidated subsidiaries. References in this report to "EnLink Midstream Partners, LP," the "Partnership," "ENLK," or like terms refer to EnLink Midstream Partners, LP itself or EnLink Midstream Partners, LP together with its consolidated subsidiaries, including the Operating Partnership.

Overview

ENLC is a Delaware limited liability company formed in October 2013. ENLC's material assets consist of all of the outstanding common units of ENLK and all of the membership interests of the General Partner. All of our midstream energy assets are owned and operated by ENLK and its subsidiaries. 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 11,900 miles of pipelines, 22 natural gas processing plants with approximately 5.5 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. We have five reportable 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;

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

- *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;

- *North Texas Segment.* The North Texas segment includes our natural gas gathering, processing, and transmission activities in North Texas; 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 manage our consolidated operations by focusing on adjusted gross 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. Adjusted gross margin is a non-GAAP financial measure and is explained in greater detail under "Non-GAAP Financial Measures" below. Approximately 94% of our adjusted gross margin was derived from fee-based contractual arrangements with minimal direct commodity price exposure for the year ended December 31, 2020.

Our revenues and adjusted gross margins are generated from eight primary sources:

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

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 adjusted gross 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,		
	2020	2019	2018
Devon	14.4 %	10.5 %	10.4 %
Dow Hydrocarbons and Resources LLC	13.2 %	10.0 %	11.1 %
Marathon Petroleum Corporation	12.2 %	13.8 %	11.5 %

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 adjusted gross 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 adjusted gross margins from our gathering and processing services primarily through different contractual arrangements: processing margin ("margin") contracts, POL contracts, POP contracts, fixed-fee based 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 adjusted gross margins are higher during periods of high NGL prices relative to natural gas prices. Adjusted gross margin results under POL contracts are impacted only by the value of the liquids produced with margins higher during periods of higher liquids prices. Adjusted gross 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 adjusted gross 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 Affecting Industry Conditions and Our Business

COVID-19 Update

On March 11, 2020, the World Health Organization declared the ongoing coronavirus (COVID-19) outbreak a pandemic and recommended containment and mitigation measures worldwide. The ongoing pandemic has reached every region of the globe and has resulted in widespread adverse impacts on the global economy, on the energy industry as a whole and on midstream companies, and on our customers, suppliers, and other parties with whom we have business relations. The pandemic and related travel and operational restrictions, as well as business closures and curtailed consumer activity, have resulted in a reduction in global demand for energy, volatility in the market prices for crude oil, condensate, natural gas and NGLs, and a significant reduction in the market price of crude oil during the first half of 2020. As a result of the demand destruction, reduced commodity prices, and an uncertain timeline for full recovery, many oil and natural gas producers, including some of our customers, curtailed their current drilling and production activity and reduced or slowed down their plans for future drilling and production activity. As a result of these decreases in producer activity, we experienced reduced volumes gathered, processed, fractionated, and transported on our assets in some of the regions that supply our systems during the first half of 2020. Although volumes have since been restored nearly to pre-pandemic levels, capital investments by oil and natural gas producers remain at low levels.

Since the outbreak began, our first priority has been the health and safety of our employees and those of our customers and other business counterparties. In March, we implemented preventative measures and developed a response plan to minimize unnecessary risk of exposure and prevent infection, while supporting our customers' operations, and we continue to follow these plans. We maintain a crisis management team for health, safety and environmental matters and personnel issues and a cross-functional COVID-19 response team to address various impacts of the situation, as they develop. We also continue to follow modified business practices (including discontinuing non-essential business travel, implementing work-from-home policies during high-transmission periods, and staggered work-from-home policies for employees who can execute their work remotely in order to reduce office density, and encouraging employees to adhere to local and regional social distancing recommendations) to support efforts to reduce the spread of COVID-19 and to conform to government restrictions and best practices encouraged by the Centers for Disease Control and Prevention, the World Health Organization, and other governmental and regulatory authorities. We also have promoted heightened awareness and vigilance, hygiene, and implementation of more stringent cleaning protocols across our facilities and operations. We continue to evaluate and adjust these preventative measures, response plans and business practices with the evolving impacts of COVID-19.

There is considerable uncertainty regarding how long the COVID-19 pandemic will persist and affect economic conditions and the extent and duration of changes in consumer behavior, such as the reluctance to travel, as well as whether governmental and other measures implemented to try to slow the spread of the virus, such as large-scale travel bans and restrictions, border closures, quarantines, shelter-in-place orders, and business and government shutdowns that exist as of the date of this report will be extended or whether new measures will be imposed. A sustained significant decline in oil and natural gas exploration and production activities and related reduced demand for our services by our customers, whether due to decreases in consumer demand or reduction in the prices for oil, condensate natural gas and NGLs or otherwise, would have a material adverse effect on our business, liquidity, financial condition, results of operations, and cash flows (including our ability to make distributions to our unitholders).

As of the date of this report, our efforts to respond to the challenges presented by the conditions described above and minimize the impacts to our business have yielded results. Our systems, pipelines, and facilities have remained operational throughout the period. We have also moved quickly and decisively, and we continue to adapt and respond promptly, to implement strategies to reduce costs, increase operational efficiencies, and lower our capital spending. We reduced our capital expenditures in 2020, including both growth and maintenance capital expenditures, to $262.6 million, a 65% reduction from 2019 total capital spending. We have also reduced costs across our platform. We reduced our general and administrative and operating expenses by $142.6 million for the year ended December 31, 2020 compared to the year ended December 31, 2019. We have not requested any funding under any federal or other governmental programs related to COVID-19 to support our operations, and we do not expect to utilize any such funding. We are continuing to address concerns to protect the health and safety of our employees and those of our customers and other business counterparties, and this includes changes to comply with health-related guidelines as they are modified and supplemented.

We cannot predict the full impact that the COVID-19 pandemic or the volatility in oil and natural gas markets related to COVID-19 will have on our business, liquidity, financial condition, results of operations, and cash flows (including our ability to make distributions to unitholders) at this time due to numerous uncertainties. The ultimate impacts will depend on future developments, including, among others, the ultimate duration and persistence of the pandemic, the speed at which the population is vaccinated against the virus and the efficacy of the vaccines, the effect of the pandemic on economic, social and other aspects of everyday life, the consequences of governmental and other measures designed to prevent the spread of the virus, actions taken by members of OPEC+ and other foreign, oil-exporting countries, actions taken by governmental authorities, customers, suppliers, and other third parties, and the timing and extent to which normal economic, social and operating conditions resume.

For additional discussion regarding risks associated with the COVID-19 pandemic, see "Item 1A—Risk Factors—The ongoing coronavirus (COVID-19) pandemic has adversely affected and could continue to adversely affect our business, financial condition, and results of operations."

Regulatory Developments

On January 20, 2021, the Biden Administration came into office and immediately issued a number of executive orders related to the production of oil and gas that could affect our operations and those of our customers. On January 20, 2021, the Acting Secretary for the Department of the Interior signed an order effectively suspending new fossil fuel leasing and permitting on federal lands for 60 days. Then on January 27, 2021, President Biden issued an executive order indefinitely suspending new oil and natural gas leases on public lands or in offshore waters pending completion of a comprehensive review and reconsideration of federal oil and gas permitting and leasing practices. In addition, on January 20, 2021, President Biden issued an Executive Order on "Protecting Public Health and the Environment and Restoring Science to Tackle the Climate Crisis" seeking to adopt new regulations and policies to address climate change and suspend, revise, or rescind, prior agency actions that are identified as conflicting with the Biden Administration's climate policies. Among the areas that could be affected by the review are regulations addressing methane emissions and the part of the extraction process known as hydraulic fracturing. The Biden Administration has also issued other orders that could ultimately affect our business, such as the executive order rejoining the Paris Agreement, and could seek, in the future, to put into place additional executive orders, policy and regulatory reviews, and seek to have Congress pass legislation that could adversely affect the production of oil and gas assets and our operations and those of our customers.

Only a small percentage of our operations are derived from customers operating on public land, mainly in the Delaware Basin, and these activities represented only approximately 3% of our total segment profit, net to EnLink, during 2020. In addition, we have a robust program to monitor and prevent methane emissions in our operations and we maintain a comprehensive environmental program that is embedded in our operations. However, our activities that take place on public lands require that we and our customers obtain permits and other approvals from the federal government. While we are still evaluating the effects of these recent orders on our operations and our customers' operations, and the status of recent and future rules and rulemaking initiatives under the Biden Administration remain uncertain, these orders, and the regulations and the policies that could result from them, could lead to increased costs for us or our customers, difficulties in obtaining permits and other approvals for us and our customers, reduced utilization of our gathering, processing and pipeline systems or reduced rates under renegotiated transportation or storage agreements in affected regions. These impacts could, in turn, adversely affect our business, financial condition, results of operation or cash flows, including our ability to make cash distributions to our unitholders.

For more information, see our risk factors under “Environmental, Legal Compliance and Regulatory Risk” in Section 1A “Risk Factors.”

Organic Growth

War Horse Processing Plant. In December 2020, we began moving equipment and facilities previously associated with the Battle Ridge processing plant in Central Oklahoma to the Permian Basin. This relocation is expected to increase the processing capacity of our Permian Basin processing facilities by approximately 80 MMcf/d. We expect to complete the relocation in the second half of 2021.

Riptide Processing Plant. The Riptide processing plant is a gas processing plant located in the Midland Basin. In September 2019, we completed an expansion to our Riptide processing plant, which increased the processing capacity by 65 MMcf/d. In March 2020, we completed an expansion to the Riptide processing plant, which increased the processing capacity by 55 MMcf/d. As of December 31, 2020, the total operational processing capacity of the Riptide processing plant was 220 MMcf/d.

Tiger Plant. The Tiger plant is a gas processing plant located in the Delaware Basin. This processing plant is owned by the Delaware Basin JV. In August 2020, we completed the construction of the Tiger plant, which expanded our Delaware Basin processing capacity by an additional 240 MMcf/d, to handle expected future processing volume growth. The Tiger plant is not operating at this time.

Central Oklahoma Plants. In June 2019, we completed construction on our Thunderbird plant, which expanded 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. The Thunderbird plant is not operating at this time.

Cajun-Sibon Pipeline. In April 2019, we completed the expansion of our Cajun-Sibon NGL pipeline capacity, which connected the Mont Belvieu NGL hub to our fractionation facilities in Louisiana. This was the third phase of our Cajun-Sibon system referred to as Cajun Sibon III, which increased 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 120 MMcf/d expansion to our Lobo III cryogenic gas processing plant, bringing the total operational processing capacity at our Lobo facilities to 395 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.

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.

Long-Term Debt Issuances, Redemption, and Repurchases

On October 21, 2020, EnLink Midstream Funding, LLC, a bankruptcy-remote special purpose entity that is an indirect subsidiary of ENLC (the “SPV”) entered into the AR Facility to borrow up to $250.0 million. In connection with the AR Facility, certain subsidiaries of ENLC have sold and contributed, and will continue to sell or contribute, their accounts receivable to the SPV to be held as collateral for borrowings under the AR Facility. The SPV’s assets are not available to satisfy the obligations of ENLC or any of its affiliates.

On December 14, 2020, ENLC issued $500.0 million in aggregate principal amount of ENLC’s 5.625% senior unsecured notes due January 15, 2028 (the “2028 Notes”) at a price to the public of 100% of their face value. Interest payments on the 2028 Notes are payable on January 15 and July 15 of each year, beginning on July 15, 2021. The 2028 Notes are fully and unconditionally guaranteed by ENLK. Net proceeds of approximately $494.7 million were used to repay a portion of the borrowings under the Term Loan due December 2021.

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.

For the year ended December 31, 2020, we made aggregate payments to partially repurchase the 2024, 2025, 2026, and 2029 Notes in open market transactions. Activity related to the partial repurchases of our outstanding debt consisted of the following (in millions):

	Year Ended December 31, 2020
Debt repurchased	$ 67.7
Aggregate payments	(36.0)
Net discount on repurchased debt	(0.3)
Accrued interest on repurchased debt	0.6
Gain on extinguishment of debt	$ 32.0

See "Item 8. Financial Statements and Supplementary Data—Note 6" for more information regarding the AR Facility, the Term Loan, and the senior unsecured notes.

Common Unit Repurchase Program. In November 2020, the board of directors of the Managing Member authorized a common unit repurchase program for the repurchase of up to $100 million of outstanding ENLC common units. The repurchases will be made, in accordance with applicable securities laws, from time to time in open market or private transactions and may be made pursuant to a trading plan meeting the requirements of Rule 10b5-1 under the Securities Exchange Act of 1934, as amended. The repurchases will depend on market conditions and may be discontinued at any time. For the year ended December 31, 2020, ENLC repurchased 383,614 outstanding ENLC common units for an aggregate price of $1.2 million.

Non-GAAP Financial Measures

To assist management in assessing our business, we use the following non-GAAP financial measures: Adjusted gross margin, adjusted earnings before interest, taxes, and depreciation and amortization ("adjusted EBITDA"), distributable cash flow available to common unitholders ("distributable cash flow"), and free cash flow after distributions.

Adjusted Gross Margin

We define adjusted gross margin as revenues less cost of sales, exclusive of operating expenses and depreciation and amortization related to our operating segments. We present adjusted gross margin by segment in "Results of Operations." We disclose adjusted gross margin in addition to gross margin as defined by GAAP because it is the primary performance measure used by our management to evaluate consolidated operations. We believe adjusted gross 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 the 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 exclude all operating expenses and depreciation and amortization related to our operating segments from adjusted gross 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 adjusted gross margin is gross margin. Adjusted gross margin should not be considered an alternative to, or more meaningful than, gross margin as determined in accordance with GAAP. Adjusted gross margin has important limitations because it excludes all operating expenses and depreciation and amortization related to our operating segments that affect gross margin. Our adjusted gross 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 reconciles total revenues and gross margin to adjusted gross margin (in millions):

	Year Ended December 31,	
	2020	2019
Total revenues	$ 3,893.8	$ 6,052.9
Cost of sales, exclusive of operating expenses and depreciation and amortization (1)	(2,388.5)	(4,392.5)
Operating expenses	(373.8)	(467.1)
Depreciation and amortization	(638.6)	(617.0)
Gross margin	492.9	576.3
Operating expenses	373.8	467.1
Depreciation and amortization	638.6	617.0
Adjusted gross margin	$ 1,505.3	$ 1,660.4

(1) Excludes all operating expenses as well as depreciation and amortization related to our operating segments of $631.3 million and $608.6 million for the years ended December 31, 2020 and 2019, respectively.

Adjusted EBITDA

We define adjusted EBITDA as net income (loss) plus (less) interest expense, net of interest income; depreciation and amortization; impairments; loss on secured term loan receivable, (income) loss from unconsolidated affiliate investments; distributions from unconsolidated affiliate investments; (gain) loss on disposition of assets; (gain) loss on extinguishment of debt; unit-based compensation; income tax expense (benefit); unrealized (gain) loss on commodity swaps; (payments under onerous performance obligation); transaction costs; relocation costs associated with the War Horse processing facility; accretion expense associated with asset retirement obligations; (non-cash rent); and (non-controlling interest share of adjusted EBITDA from joint ventures). Adjusted EBITDA is the primary metric used in our short-term incentive program for compensating employees. In addition, adjusted EBITDA is used as a supplemental liquidity and performance measure by our management and by external users of our financial statements, such as investors, commercial banks, research analysts, and others, to assess:

- the financial performance of our assets without regard to financing methods, capital structure, or historical cost basis;
- the ability of our assets to generate cash sufficient to pay interest costs, support our indebtedness, and make cash distributions to our unitholders;
- our operating performance and return on capital as compared to those of other companies in the midstream energy sector, without regard to financing methods or capital structure; and
- the viability of acquisitions and capital expenditure projects and the overall rates of return on alternative investment opportunities.

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

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

The following table reconciles net loss to adjusted EBITDA (in millions):

	Year Ended December 31,	
	2020	2019
Net loss	$ (315.6)	$ (999.6)
Interest expense, net of interest income	223.3	216.0
Depreciation and amortization	638.6	617.0
Impairments	362.8	1,133.5
Loss on secured term loan receivable (1)	—	52.9
(Income) loss from unconsolidated affiliate investments (2)	(0.6)	16.8
Distributions from unconsolidated affiliate investments	2.1	20.2
(Gain) loss on disposition of assets	8.8	(1.9)
Gain on extinguishment of debt	(32.0)	—
Unit-based compensation	28.4	39.4
Income tax expense	143.2	6.9
Unrealized loss on commodity swaps	10.5	0.1
Payments under onerous performance obligation offset to other current and long-term liabilities	—	(9.0)
Transaction costs (3)	—	13.9
Relocation costs associated with the War Horse processing facility (4)	0.8	—
Other (5)	(1.1)	(1.0)
Adjusted EBITDA before non-controlling interest	1,069.2	1,105.2
Non-controlling interest share of adjusted EBITDA from joint ventures (6)	(30.7)	(25.7)
Adjusted EBITDA, net to ENLC	$ 1,038.5	$ 1,079.5

(1) We 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 secured term loan receivable. For additional information regarding this transaction, refer to “Item 8. Financial Statements and Supplementary Data—Note 2.”
(2) Includes 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.
(3) Represents transaction costs attributable to costs incurred related to the Merger in January 2019.
(4) Represents cost incurred related to the relocation of equipment and facilities from the Battle Ridge processing plant, in the Oklahoma segment, to the Permian segment that we expect to complete in 2021 and are not part of our ongoing operations.
(5) Includes accretion expense associated with asset retirement obligations and non-cash rent, which relates to lease incentives pro-rated over the lease term.
(6) Non-controlling interest share of adjusted EBITDA from joint ventures includes NGP’s 49.9% share of adjusted EBITDA from the Delaware Basin JV, Marathon Petroleum Corporation’s 50% share of adjusted EBITDA from the Ascension JV, and other minor non-controlling interests.

Distributable Cash Flow and Free Cash Flow After Distributions

We define distributable cash flow as adjusted EBITDA, net to ENLC, plus (less) (interest expense, net of interest income); (maintenance capital expenditures, excluding maintenance capital expenditures that were contributed by other entities and relate to the non-controlling interest share of our consolidated entities); (accrued cash distributions on Series B Preferred Units and Series C Preferred Units paid or expected to be paid); (payments to terminate interest rate swaps); non-cash interest (income)/expense; and (current income taxes).

Free cash flow after distributions is defined as distributable cash flow plus (less) (distributions declared on common units); (growth capital expenditures, excluding growth capital expenditures that were contributed by other entities and relate to the non-controlling interest share of our consolidated joint ventures); proceeds from the sale of equipment and land; and (relocation costs associated with the War Horse processing facility).

Free cash flow after distributions is the principal cash flow metric used by the Company in its earnings announcements. In addition, distributable cash flow and free cash flow after distributions are used as supplemental liquidity measures by our management and by external users of our financial statements, such as investors, commercial banks, research analysts, and others, to assess the ability of our assets to generate cash sufficient to pay interest costs, pay back our indebtedness, make cash distributions, and make capital expenditures.

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

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.

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

The following table reconciles net cash provided by operating activities to adjusted EBITDA, distributable cash flow, and free cash flow after distributions (in millions):

	Year Ended December 31,	
	2020	2019
Net cash provided by operating activities	$ 731.1	$ 991.9
Interest expense (1)	218.2	213.7
Payments to terminate interest rate swaps (2)	10.9	—
Accruals for settled commodity swap transactions	(4.3)	(2.4)
Current income tax expense	1.1	—
Distributions from unconsolidated affiliate investment in excess of earnings	0.5	3.7
Transaction costs (3)	—	13.9
Relocation costs associated with the War Horse processing facility (4)	0.8	—
Other (5)	(0.3)	(1.4)
Changes in operating assets and liabilities which (provided) used cash:		
Accounts receivable, accrued revenues, inventories, and other	6.4	(350.7)
Accounts payable, accrued product purchases, and other accrued liabilities (6)	104.8	236.5
Adjusted EBITDA before non-controlling interest	1,069.2	1,105.2
Non-controlling interest share of adjusted EBITDA from joint ventures (7)	(30.7)	(25.7)
Adjusted EBITDA, net to ENLC	1,038.5	1,079.5
Interest expense, net of interest income	(223.3)	(216.0)
Maintenance capital expenditures, net to ENLC (8)	(32.1)	(45.8)
ENLK preferred unit accrued cash distributions (9)	(91.4)	(91.7)
Payments to terminate interest rate swaps (2)	(10.9)	—
Other (10)	(0.9)	(2.2)
Distributable cash flow	679.9	723.8
Common distributions declared	(186.0)	(508.1)
Growth capital expenditures, net to ENLC (8)	(187.2)	(599.8)
Proceeds from the sale of equipment and land (11)	4.6	8.2
Relocation costs associated with the War Horse processing facility (4)	(0.8)	—
Free cash flow after distributions	$ 310.5	$ (375.9)

(1) Net of amortization of debt issuance costs and discount and premium, which are included in interest expense but not included in net cash provided by operating activities, and non-cash interest income/(expense), which is netted against interest expense but not included in adjusted EBITDA.
(2) Represents cash paid for the early termination of $500.0 million of our interest rate swaps due to the partial repayment of the Term Loan in December 2020. See "Item 8. Financial Statements and Supplementary Data—Note 12" for information on the partial termination of our interest rate swaps.
(3) Represents transaction costs incurred related to the Merger in January 2019.
(4) Represents cost incurred related to the relocation of equipment and facilities from the Battle Ridge processing plant, in the Oklahoma segment, to the Permian segment that we expect to complete in 2021 and are not part of our ongoing operations.
(5) Includes amortization of designated cash flow hedge and non-cash rent, which relates to lease incentives pro-rated over the lease term.
(6) Net of payments under onerous performance obligation offset to other current and long-term liabilities during the year ended December 31, 2019.
(7) Non-controlling interest share of adjusted EBITDA from joint ventures includes NGP's 49.9% share of adjusted EBITDA from the Delaware Basin JV, Marathon Petroleum Corporation's 50% share of adjusted EBITDA from the Ascension JV, and other minor non-controlling interests.
(8) Excludes capital expenditures that were contributed by other entities and relate to the non-controlling interest share of our consolidated entities.
(9) Represents the cash distributions earned by the Series B Preferred Units and Series C Preferred Units. See "Item 8. Financial Statements and Supplementary Data—Note 8" for information on the cash distributions earned by holders of the Series B Preferred Units and Series C Preferred Units. Cash distributions to be paid to holders of the Series B Preferred Units and Series C Preferred Units are not available to common unitholders.
(10) Includes non-cash interest (income)/expense and current income tax expense.
(11) Represents proceeds from the sale of surplus or unused equipment and land. These sales occurred in the normal operation of our business and did not include major divestitures.

Results of Operations

The tables below set forth certain financial and operating data for the periods indicated. We evaluate the performance of our consolidated operations by focusing on adjusted gross margin, while we evaluate the performance of our operating segments based on segment profit and adjusted gross margin, as reflected in the table below (in millions, except volumes):

	Permian	Louisiana	Oklahoma	North Texas	Corporate	Totals
Year Ended December 31, 2020						
Gross margin	$ 44.9	$ 152.3	$ 197.4	$ 127.6	$ (29.3)	$ 492.9
Add:						
Depreciation and amortization	125.2	145.8	216.9	143.4	7.3	638.6
Segment profit	170.1	298.1	414.3	271.0	(22.0)	1,131.5
Operating expenses	94.2	120.0	82.2	77.4	—	373.8
Adjusted gross margin	$ 264.3	$ 418.1	$ 496.5	$ 348.4	$ (22.0)	$ 1,505.3

	Permian	Louisiana	Oklahoma	North Texas	Corporate	Totals
Year Ended December 31, 2019						
Gross margin	$ 25.7	$ 139.8	$ 255.2	$ 149.6	$ 6.0	$ 576.3
Add:						
Depreciation and amortization	119.8	154.1	194.9	139.8	8.4	617.0
Segment profit	145.5	293.9	450.1	289.4	14.4	1,193.3
Operating expenses	112.9	147.3	104.0	102.9	—	467.1
Adjusted gross margin	$ 258.4	$ 441.2	$ 554.1	$ 392.3	$ 14.4	$ 1,660.4

	Year Ended December 31,	
	2020	2019
Midstream Volumes:		
Permian Segment		
Gathering and Transportation (MMbtu/d)	890,800	723,400
Processing (MMbtu/d)	899,000	771,400
Crude Oil Handling (Bbls/d)	116,200	132,000
Louisiana Segment		
Gathering and Transportation (MMbtu/d)	1,993,900	2,050,000
Crude Oil Handling (Bbls/d)	16,900	18,900
NGL Fractionation (Gals/d)	7,597,800	7,341,700
Brine Disposal (Bbls/d)	1,300	2,700
Oklahoma Segment		
Gathering and Transportation (MMbtu/d)	1,116,500	1,302,200
Processing (MMbtu/d)	1,105,900	1,276,700
Crude Oil Handling (Bbls/d)	28,700	47,300
North Texas Segment		
Gathering and Transportation (MMbtu/d)	1,478,200	1,651,900
Processing (MMbtu/d)	671,000	750,500

Year Ended December 31, 2020 Compared to Year Ended December 31, 2019

Gross Margin. Gross margin was $492.9 million for the year ended December 31, 2020 compared to $576.3 million for the year ended December 31, 2019, a decrease of $83.4 million. The primary contributors to the total decrease were as follows (in millions):

- *Permian Segment.* Gross margin was $44.9 million for the year ended December 31, 2020 compared to $25.7 million for the year ended December 31, 2019, an increase of $19.2 million primarily due to the following:

  ◦ Adjusted gross margin in the Permian segment increased $5.9 million, which was primarily driven by:

    - A $5.9 million increase due to volume growth in our Delaware Basin crude assets.
    - An $8.3 million increase related to volume growth from additional well connects on our Midland Basin gas assets.
    - A $7.5 million increase related to volume growth from additional well connects on our Delaware Basin gas assets.

    These increases were partially offset by a $15.8 million decrease on our South Texas assets primarily due to the expiration of an MVC provision in one of our contracts in July 2019 and the sale of the VEX assets in October 2020.

  ◦ Operating expenses in the Permian segment decreased $18.7 million primarily due to decreased labor and benefits expense as a result of reductions in workforce and reductions in materials and supplies expense, construction fees and services, vehicle expenses, and sales and use tax.

  ◦ Depreciation and amortization in the Permian segment increased $5.4 million primarily due to new assets placed into service, including the expansion to our Riptide processing plant and the completed construction of our Tiger plant.

- *Louisiana Segment.* Gross margin was $152.3 million for the year ended December 31, 2020 compared to $139.8 million for the year ended December 31, 2019, an increase of $12.5 million primarily due to the following:

  ◦ Adjusted gross margin in the Louisiana segment decreased $23.1 million, resulting from:

    - A $12.8 million decrease from our Louisiana gas assets due to the expiration of certain firm transportation contracts, and decreased gathering and transportation volumes.
    - A $16.9 million decrease from our ORV crude assets primarily due to lower volumes.

    These decreases were partially offset by a $6.6 million increase from our NGL transmission and fractionation assets, which was primarily due to higher volumes that resulted from the completion of the Cajun-Sibon pipeline expansion in April 2019 and a settlement payment received as the result of a contract dispute in the amount of $5.5 million.

  ◦ Operating expenses in the Louisiana segment decreased $27.3 million primarily due to decreased labor and benefits expense as a result of reductions in workforce and reductions in materials and supplies expense, utilities, construction fees and services, compressor rentals, and vehicle expenses.

  ◦ Depreciation and amortization in the Louisiana segment decreased $8.3 million primarily due to the impairment of Louisiana segment assets in the first quarter of 2020.

- *Oklahoma Segment.* Gross margin was $197.4 million for the year ended December 31, 2020 compared to $255.2 million for the year ended December 31, 2019, a decrease of $57.8 million primarily due to the following:

  ◦ Adjusted gross margin in the Oklahoma segment decreased $57.6 million, resulting from:

    - A $5.9 million decrease due to volume decline in our Oklahoma crude assets primarily due to lower volumes from our existing customers.
    - A $51.7 million decrease due to volume decline in our Oklahoma gas assets primarily due to lower volumes from our existing customers.

- Operating expenses in the Oklahoma segment decreased $21.8 million primarily due to decreased labor and benefits expense as a result of reductions in workforce and reductions in materials and supplies expense, construction fees and services, and compressor rentals.

- Depreciation and amortization in the Oklahoma segment increased $22.0 million primarily due to the Thunderbird plant, which was operational in June 2019, as well as a change in the estimated useful lives of certain non-core assets.

• *North Texas Segment.* Gross margin was $127.6 million for the year ended December 31, 2020 compared to $149.6 million for the year ended December 31, 2019, a decrease of $22.0 million primarily due to the following:

- Adjusted gross margin in the North Texas segment decreased $43.9 million, which was primarily due to volume declines resulting from limited new drilling in the region.

- Operating expenses in the North Texas segment decreased $25.5 million primarily due to decreased labor and benefits expense as a result of reductions in workforce and reductions in materials and supplies expense, operations and maintenance, fees and services, sales and use tax, ad valorem taxes, and compressor rentals.

- Depreciation and amortization in the North Texas segment increased $3.6 million primarily due to a change in the estimated useful lives of certain non-core assets and the conclusion of a finance lease in the North Texas segment in 2019.

• *Corporate Segment.* Gross margin was negative $29.3 million for the year ended December 31, 2020 compared to $6.0 million for the year ended December 31, 2019, a decrease of $35.3 million primarily due to the following:

- Adjusted gross margin in the Corporate segment decreased $36.4 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,	
	2020	**2019**
Realized swaps:		
Crude swaps	$ (3.2)	$ 11.7
NGL swaps	(6.7)	6.5
Gas swaps	(1.6)	(3.7)
Realized gain (loss) on derivatives	(11.5)	14.5
Unrealized swaps:		
Crude swaps	3.1	(0.3)
NGL swaps	(15.7)	(3.5)
Gas swaps	2.1	3.7
Change in fair value of derivatives	(10.5)	(0.1)
Gain (loss) on derivative activity	$ (22.0)	$ 14.4

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

	Year Ended December 31,	
	2020	2019
Permian segment	$ 1.0	$ 9.4
Oklahoma segment	56.2	10.3
Total	$ 57.2	$ 19.7

Impairments. For the year ended December 31, 2020, we recognized impairment expense related to goodwill; property and equipment, including cancelled projects; and lease right-of-use assets. For the year ended December 31, 2019, we recognized impairment expense related to goodwill and property and equipment. Impairment expense is composed of the following amounts (in millions):

	Year Ended December 31,	
	2020	2019
Goodwill impairment (1)	$ 184.6	$ 1,125.6
Property and equipment impairment (2)	168.0	7.9
Lease right-of-use asset impairment (3)	6.8	—
Cancelled projects (2)	3.4	—
Total impairments	$ 362.8	$ 1,133.5

(1) For additional information see "Item 8. Financial Statements and Supplementary Data—Note 3."
(2) For additional information see "Item 8. Financial Statements and Supplementary Data—Note 2."
(3) For additional information see "Item 8. Financial Statements and Supplementary Data—Note 5."

Gain (loss) on disposition of assets. For the year ended December 31, 2020, we recorded an $8.8 million loss on disposition of assets primarily related to the sale of our non-core crude pipeline assets in South Texas. For the year ended December 31, 2019, we recorded a $1.9 million gain on disposition of assets primarily related to sale of non-core assets.

General and administrative expenses. General and administrative expenses were $103.3 million for the year ended December 31, 2020 compared to $152.6 million for the year ended December 31, 2019, a decrease of $49.3 million. The primary contributors to the decrease were as follows:

- Transaction costs decreased $13.9 million, which was primarily due to costs incurred related to the Merger, which closed during the first quarter of 2019.
- Labor costs and unit-based compensation decreased $24.5 million due to reductions in workforce and lower bonus accrual.
- Expenses related to fees and services, travel, rents and leases, and insurance decreased $8.7 million, which was primarily due to general cost saving initiatives.

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 $223.3 million for the year ended December 31, 2020 compared to $216.0 million for the year ended December 31, 2019, an increase of $7.3 million, or 3.4%. Net interest expense consisted of the following (in millions):

	Year Ended December 31,	
	2020	2019
ENLC and ENLK senior notes	$ 175.0	$ 171.4
Term Loan	17.5	32.5
Consolidated Credit Facility	13.9	13.9
AR Facility	0.9	—
Capitalized interest	(3.4)	(5.8)
Amortization of debt issuance costs, net (premium) discount of notes	4.6	4.9
Interest rate swaps - realized	14.5	0.4
Other	0.3	(1.3)
Total interest expense, net of interest income	$ 223.3	$ 216.0

Gain on extinguishment of debt. We recognized a gain on extinguishment of debt of $32.0 million for the year ended December 31, 2020 due to repurchases of the 2024, 2025, 2026, and 2029 Notes in open market transactions. See "Item 8. Financial Statements and Supplementary Data—Note 6" for additional information.

Income (loss) from Unconsolidated Affiliate Investments. Income from unconsolidated affiliate investments was $0.6 million for the year ended December 31, 2020 compared to a loss of $16.8 million for the year ended December 31, 2019, an increase in income of $17.4 million. The increase in income was primarily due to a $31.4 million impairment of the carrying value of the Cedar Cove JV for the year ended December 31, 2019, as we determined that the carrying value of our investment was not recoverable based on the forecasted cash flows from the Cedar Cove JV. This was partially offset by a reduction in income of $13.5 million from our GCF investment as a result of lower fractionation revenues. See "Item 8. Financial Statements and Supplementary Data—Note 10" for additional information.

Income Tax Benefit (Expense). Income tax expense was $143.2 million for the year ended December 31, 2020 compared to income tax expense of $6.9 million for the year ended December 31, 2019, an increase of tax expense of $136.3 million primarily due to a change in the valuation allowance recorded on our deferred tax assets. See "Item 8. Financial Statements and Supplementary Data—Note 7" for additional information.

Net Income (Loss) Attributable to Non-controlling Interest. Net income attributable to non-controlling interest was $105.9 million for the year ended December 31, 2020 compared to net income of $119.7 million for the year ended December 31, 2019, a decrease of $13.8 million. This decrease was primarily due to the conversion of ENLK common units into ENLC common units as a result of the Merger in the first quarter of 2019. Subsequent to the Merger, ENLC's non-controlling interest is comprised of Series B Preferred Units, Series C Preferred Units, NGP's 49.9% share of the Delaware Basin JV, Marathon Petroleum Corporation's 50% share of the Ascension JV, and other minor non-controlling interests.

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

We evaluate long-lived assets, including property and equipment, intangible assets, equity method investments, and lease right-of-use assets, for potential impairment whenever events or changes in circumstances indicate that their carrying value may not be recoverable. The carrying amount of a long-lived asset is not recoverable when it exceeds the undiscounted sum of the future cash flows expected to result from the use and eventual disposition of the asset. Estimates of expected future cash flows represent management's best estimate based on reasonable and supportable assumptions. When the carrying amount of a long-lived asset is not recoverable, an impairment 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."

Property and Equipment Impairments. During March 2020, we determined that a sustained decline in our unit price and weakness in the overall energy sector, driven by low commodity prices and lower consumer demand due to the COVID-19 pandemic, caused a change in circumstances warranting an interim impairment test related to our property and equipment carrying amounts. For the year ended December 31, 2020, we recognized a $168.0 million impairment on property and equipment related to a portion of our Louisiana reporting segment because the carrying amounts were not recoverable based on our expected future cash flows, and $3.4 million of impairments related to certain cancelled projects. 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.

Lease Right-of-Use Asset Impairment. During the fourth quarter of 2020, we determined that we would cease using a portion of our Dallas, Houston, and Midland offices. We are attempting to sublease the vacated space; however, as we believe the terms of a sublease would be below our current rental rates, we evaluated the related right-of-use assets for impairment by comparing the estimated fair values of the right-of-use assets to their carrying values. Estimated fair values were calculated using a discounted cash flow analysis that utilized Level 3 inputs, which included estimated future cash flows and a discount rate derived from market data. As the carrying value of each right-of-use asset exceeded its estimated fair value, we recognized impairment expense of $6.8 million for the year ended December 31, 2020.

To the extent conditions further deteriorate in the current worldwide economic and commodity price environment, we may identify additional triggering events that may require future evaluations of the recoverability of the carrying value of our long-lived assets, which could result in further impairment charges.

Liquidity and Capital Resources

Cash Flows from Operating Activities. Net cash provided by operating activities was $731.1 million for the year ended December 31, 2020 compared to $991.9 million for the year ended December 31, 2019. Operating cash flows and changes in working capital for comparative periods were as follows (in millions):

	Year Ended December 31,	
	2020	2019
Operating cash flows before working capital	$ 842.3	$ 886.7
Changes in working capital	(111.2)	105.2

Operating cash flows before changes in working capital decreased $44.4 million for the year ended December 31, 2020 compared to the year ended December 31, 2019. The primary contributors to the decrease in operating cash flows were as follows:

- Gross margin, excluding depreciation and amortization, non-cash commodity swap activity, and unit-based compensation, decreased $49.1 million. For more information regarding the changes in gross margin for the year ended December 31, 2020 compared to the year ended December 31, 2019, see "Results of Operations."
- Distribution of earnings from unconsolidated affiliates decreased $14.9 million.
- Interest expense, excluding amortization of debt issue costs and net discounts, increased $7.6 million.
- A $10.9 million cash payment for the early termination of $500.0 million of our interest rate swaps due to the partial repayment of the Term Loan in December 2020.

These changes to operating cash flows were offset by the following:

- General and administrative expenses excluding unit-based compensation decreased $37.9 million, primarily due to a reduction in costs across our platform, reductions in workforce, and transaction costs related to the Merger in 2019. For more information, see “Results of Operations.”

The changes in working capital for the years ended December 31, 2020 and 2019 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.

Historically, we have had net operating losses that eliminated substantially all of our taxable income, and thus, we have not historically paid significant amounts of income taxes. We anticipate generating net operating losses for tax purposes during 2021, and as a result, do not expect to incur material amounts of federal and state income tax liabilities. In the event that we do generate taxable income that exceeds our utilizable net operating loss carryforwards, federal and state income tax liabilities will increase cash taxes paid. Refer to “Item 8. Financial Statements and Supplementary Data—Note 7” for additional information.

Cash Flows from Investing Activities. Net cash used in investing activities was $317.7 million for the year ended December 31, 2020 compared to $741.5 million for the year ended December 31, 2019. The primary contributors to the decrease in investing cash flows were as follows:

- Capital expenditures decreased from $754.9 million for the year ended December 31, 2019 to $302.2 million for the year ended December 31, 2020. The decrease was primarily due to higher overall 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, compared to the capital expenditures in 2020 related to an additional expansion of the Riptide processing plant and the completion of the Tiger plant.

- Proceeds from the sale of assets increased from $14.3 million for the year ended December 31, 2019 to $17.6 million for the year ended December 31, 2020 related to the sale of non-core assets for each period.

These decreases to investing cash flows were partially offset by $32.3 million related to cash paid for the acquisition of assets for the year ended December 31, 2020.

Cash Flows from Financing Activities. Net cash used in financing activities was $451.2 million for the year ended December 31, 2020 compared to $273.4 million for the year ended December 31, 2019. Our primary financing activities consisted of the following (in millions):

	Year Ended December 31,	
	2020	2019
Net borrowings on the AR Facility (1)	$ 250.0	$ —
Net borrowings on ENLC senior unsecured notes (1)	499.2	500.0
Net repayments on the Term Loan (1)	(500.0)	—
Net borrowings (repayments) on the Consolidated Credit Facility (1)	(350.0)	350.0
Net repurchases on ENLK's senior unsecured notes (1)	(35.2)	—
Net repayments on ENLK's 2019 unsecured senior notes (1)	—	(400.0)
Net repayments on the ENLC Credit Facility	—	(111.4)
Debt financing costs	(7.7)	(10.0)
Distributions to Series B and Series C Preferred unitholders (2)	(91.3)	(91.4)
Distributions to joint venture partners (3)	(29.9)	(24.1)
Distributions to members	(232.7)	(467.2)
Contributions by non-controlling interest (4)	52.6	97.5
Common unit repurchases (5)	(1.2)	—
Distributions to ENLK common units held by public unitholders (6)	—	(105.0)

(1) See "Item 8. Financial Statements and Supplementary Data—Note 6" for more information regarding the AR Facility, the Term Loan, the Consolidated Credit Facility, and the senior unsecured notes.
(2) 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.
(3) Represents distributions to NGP for its ownership in the Delaware Basin JV, distributions to Marathon Petroleum Corporation for its ownership in the Ascension JV, and distributions to other non-controlling interests.
(4) Represents contributions from NGP to the Delaware Basin JV.
(5) See "Item 8. Financial Statements and Supplementary Data—Note 9" for more information regarding the ENLC common unit repurchase program.
(6) Subsequent to the closing of the Merger, ENLK no longer has publicly held common units.

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, to maintain pipeline and equipment reliability, integrity, and safety, and to address environmental laws and regulations.

We expect our 2021 capital expenditures, including capital contributions to our unconsolidated affiliate investments, to be approximately $115 million to $155 million, which is net of approximately $3 million to $5 million from our joint venture partners. Our primary capital projects for 2021 include continued development of our existing systems through well connects and other small projects. Additionally, we expect to incur $25 million of operating expenses related to the movement of equipment and facilities previously associated with the Battle Ridge processing plant in Central Oklahoma to the Permian Basin, which is not included in our expected 2021 capital expenditures.

We expect to fund 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. In 2021, 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, 2020 and 2019.

Total Contractual Cash Obligations. A summary of our total contractual cash obligations as of December 31, 2020 is as follows (in millions):

	Payments Due by Period						
	Total	2021	2022	2023	2024	2025	Thereafter
ENLC's & ENLK's senior unsecured notes	$ 4,032.3	$ —	$ —	$ —	$ 521.8	$ 720.8	$ 2,789.7
Term Loan (1)	350.0	350.0	—	—	—	—	—
Consolidated Credit Facility (2)	—	—	—	—	—	—	—
AR Facility (3)	250.0	—	—	250.0	—	—	—
Interest payable on fixed long-term debt obligations	2,523.2	188.2	201.2	201.2	189.7	163.3	1,579.6
Operating lease obligations	121.7	19.6	13.7	10.2	9.5	9.8	58.9
Purchase obligations	2.0	2.0	—	—	—	—	—
Pipeline and trucking capacity and deficiency agreements (4)	156.4	41.4	31.9	28.1	19.0	16.0	20.0
Inactive easement commitment (5)	10.0	—	10.0	—	—	—	—
Total contractual obligations	$ 7,445.6	$ 601.2	$ 256.8	$ 489.5	$ 740.0	$ 909.9	$ 4,448.2

(1) The Term Loan matures on December 10, 2021.
(2) The Consolidated Credit Facility will mature on January 25, 2024. As of December 31, 2020, there were no amounts outstanding under the Consolidated Credit Facility.
(3) The AR Facility is scheduled to terminate on October 20, 2023.
(4) Consists of pipeline capacity payments for firm transportation and deficiency agreements.
(5) 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 related to the Consolidated Credit Facility, the Term Loan, and the AR Facility are not reflected in the above table because such amounts depend on the outstanding balances and interest rates of the Consolidated Credit Facility, the Term Loan, and the AR Facility, which vary from time to time.

Our contractual cash obligations for 2021 are expected to be funded from cash flows generated from our operations and the available capacity under Consolidated Credit Facility or other debt sources.

Indebtedness

In October 2020, we entered into the AR Facility, which is a three-year committed accounts receivable securitization facility of up to $250.0 million. As of December 31, 2020, there was $250.0 million in outstanding borrowings under the AR Facility.

As of December 31, 2020, there were no outstanding borrowings under the Consolidated Credit Facility and $22.2 million in outstanding letters of credit.

In addition, as of December 31, 2020, we have $4.0 billion in aggregate principal amount of outstanding unsecured senior notes maturing from 2024 to 2047 and $350.0 million in outstanding principal on the Term Loan.

Guarantees. The amounts outstanding on our senior unsecured notes, the Term Loan, and the Consolidated Credit Facility are guaranteed in full by our subsidiary ENLK, including 105% of any letters of credit outstanding on the Consolidated Credit Facility. ENLK's guarantees of these amounts are full, irrevocable, unconditional, and absolute, and cover all payment obligations arising under the senior unsecured notes, the Term Loan, and the Consolidated Credit Facility. Liabilities under the guarantees rank equally in right of payment with all existing and future senior unsecured indebtedness of ENLK.

ENLC's material assets consist of all of the outstanding common units of ENLK and all of the membership interests of the General Partner. Other than these equity interests, all of our material assets and operations are held by our non-guarantor operating subsidiaries. ENLK, directly and indirectly, owns all of these non-guarantor operating subsidiaries, which in some cases are joint ventures that are partially owned by a third party. As a result, the assets, liabilities, and results of operations of ENLK are not materially different than the corresponding amounts presented in our consolidated financial statements.

As of December 31, 2020, ENLC records, on a stand-alone basis, transactions that do not occur at ENLK related to taxation of ENLC, the elimination of intercompany borrowings, and impairment of goodwill that only existed at ENLC.

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 2019 and 2020. Although the impact of inflation has been insignificant in recent years, it is still a factor in the United States economy and may increase the cost to acquire or replace property and equipment and may increase the costs of labor and supplies. To the extent permitted by competition, regulation, and our existing agreements, we have and will continue to pass along increased costs to our customers in the form of higher fees.

Environmental

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

Contingencies

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

Recent Accounting Pronouncements

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

Disclosure Regarding Forward-Looking Statements

This Annual Report on Form 10-K contains forward-looking statements 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 or leverage metrics, future cost savings or operational initiatives, our future capital structure and credit ratings, objectives, strategies, expectations, and intentions, the impact of the COVID-19 pandemic on us and our financial results and operations, 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) the impact of the ongoing coronavirus (COVID-19) outbreak on our business, financial condition, and results of operation, (b) 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, (c) 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, (d) a default under GIP’s credit facility could result in a change in control of us, could adversely affect the price of our common units, and could result in a default or prepayment event under our credit facility and certain of our other debt, (e) the dependence on Devon for a substantial portion of the natural gas and crude that we gather, process, and transport, (f) developments that materially and adversely affect Devon or other customers, (g) adverse developments in the midstream business that may reduce our ability to make distributions, (h) competition for crude oil, condensate, natural gas, and NGL supplies and any decrease in the availability of such commodities, (i) decreases in the volumes that we gather, process, fractionate, or transport, (j) increasing scrutiny and changing expectations from stakeholders with respect to our environment, social, and governance practices, (k) our ability to receive or renew required permits and other approvals, (l) 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, (m) climate change legislation and regulatory initiatives resulting in increased operating costs and reduced demand for the natural gas and NGL services we provide, (n) changes in the availability and cost of capital, including as a result of a change in our credit rating, (o) volatile prices and market demand for crude oil, condensate, natural gas, and NGLs that are beyond our control, (p) 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, (q) operating hazards, natural disasters, weather-related issues or delays, casualty losses, and other matters beyond our control, (r) reductions in demand for NGL products by the petrochemical, refining, or other industries or by the fuel markets, (s) impairments to goodwill, long-lived assets and equity method investments, and (t) 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 February 2020 (withdrawing previously proposed rules) that would place limits on positions in certain core futures and equivalent swaps contracts for or linked to certain physical commodities, subject to exceptions for certain bona fide hedging transactions. The CFTC adopted the proposed rules, with certain modifications, effective March 2021.

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 2020. Crude oil prices decreased 21% while weighted average NGL prices and natural gas prices each increased 20% from January 1, 2020 to December 31, 2020. We expect continued volatility in these commodity prices. For example, see the table below for the range of closing prices for crude oil, NGL, and natural gas during 2020.

Commodity	Closing Price		Date
Crude oil (high) (1)	$	63.27	January 6, 2020
Crude oil (low) (1)	$	(37.63)	April 20, 2020
Crude oil (average) (1)(4)	$	39.28	Not applicable
NGL (high) (2)	$	0.48	December 31, 2020
NGL (low) (2)	$	0.10	March 23, 2020
NGL (average) (2)(4)	$	0.31	Not applicable
Natural gas (high) (3)	$	3.35	October 30, 2020
Natural gas (low) (3)	$	1.48	June 25, 2020
Natural gas (average) (3)(4)	$	2.13	Not applicable

(1) Crude oil closing prices based on the NYMEX futures daily close prices.
(2) Weighted average NGL gas closing prices based on the Oil Price Information Service Napoleonville daily average spot liquids prices.
(3) Natural gas closing prices based on Gas Daily Henry Hub closing prices.
(4) The average closing price was computed by taking the sum of the closing prices of each trading day divided by the number of trading days during the period presented.

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 adjusted gross margin and cash flows to vary widely from period to period. Our hedging strategies may not be sufficient to offset price volatility risk and, in any event, do not cover all of our throughput volumes.

We are subject to risks due to fluctuations in commodity prices. Approximately 94% of our adjusted gross margin for the year ended December 31, 2020 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, 2020, less than 1% of our adjusted gross 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, 2020, approximately 5% of our adjusted gross 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, 2020. These derivative instruments mitigate 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 2021 - December 2021	Ethane	1,160 (MBbls)	$0.2092/Gal	Index	$ (1.2)
January 2021 - December 2021	Propane	1,385 (MBbls)	Index	$0.7069/Gal	(10.1)
January 2021 - October 2021	Normal butane	474 (MBbls)	Index	$0.7551/Gal	(2.6)
January 2021 - February 2021	Natural gasoline	100 (MBbls)	Index	$1.0939/Gal	(0.6)
January 2021 - January 2022	Natural gas	73,027 (MMbtu/d)	Index	$2.4515/MMbtu	2.6
January 2021 - January 2022	Crude and condensate	4,990 (MBbls)	Index	$48.28/Bbl	0.5
January 2021 - December 2022	Crude and condensate	7,658 (MBbls)	$1.861/Bbl	Index (2)	9.3
					$ (2.1)

(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, 2020, outstanding natural gas swap agreements, NGL swap agreements, swing swap agreements, storage swap agreements, and other derivative instruments had a net fair value liability of $2.1 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 $8.0 million in the net fair value of these contracts as of December 31, 2020.

Interest Rate Risk

We are exposed to interest rate risk on the Consolidated Credit Facility, the Term Loan, and the AR Facility. At December 31, 2020, we had $350.0 million and $250.0 million in outstanding borrowings under the Term Loan and the AR Facility, respectively. At December 31, 2020, we had no outstanding borrowings under the Consolidated Credit Facility.

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. In December 2020, in connection with the partial repayment of the Term Loan, we terminated $500.0 million of the $850.0 million interest rate swaps. See “Item 8. Financial Statements and Supplementary Data—Note 12” for more information on our outstanding derivatives.

A 1.0% increase or decrease in interest rates would change our annualized interest expense by approximately $3.5 million for the Term Loan. This change in interest expense would be partially offset by a $3.5 million change related to our open interest rate swap hedge. The AR Facility has a LIBOR floor of 0.375%. A 1.0% increase or decrease in interest rates once LIBOR exceeds the 0.375% floor would change our annualized interest expense by $2.5 million.

We are not exposed to changes in interest rates with respect to ENLK’s senior unsecured notes due in 2024, 2025, 2026, 2044, 2045, or 2047 or our senior unsecured notes due in 2028 and 2029 as these are fixed-rate obligations. As of December 31, 2020, the estimated fair value of the senior unsecured notes was approximately $3,718.2 million, based on the market prices of ENLK’s and our publicly traded debt at December 31, 2020. 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 $236.3 million decrease in fair value of the senior unsecured notes at December 31, 2020. See “Item 8. Financial Statements and Supplementary Data—Note 6” for more information on our outstanding indebtedness.

Item 8. Financial Statements and Supplementary Data

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MANAGEMENT'S REPORT ON
INTERNAL CONTROL OVER FINANCIAL REPORTING

Management of EnLink Midstream Manager, LLC, the Managing Member, 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, LLC (the "Company"). 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 Manager, 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 Company'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 Company's transactions and dispositions of the Company'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 Company are being made only in accordance with authorization of EnLink Midstream Manager, LLC's management and directors; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of the Company's assets that could have a material effect on the 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 Company's annual consolidated financial statements, management has undertaken an assessment of the effectiveness of the Company's internal control over financial reporting as of December 31, 2020, 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 Company's internal control over financial reporting and testing of the operational effectiveness of those controls.

Based on this assessment, management has concluded that as of December 31, 2020, the Company's internal control over financial reporting was effective to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with U.S. generally accepted accounting principles.

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

Report of Independent Registered Public Accounting Firm

To the Members of EnLink Midstream, LLC and
Board of Directors of EnLink Midstream Manager, LLC:

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

We have audited the accompanying consolidated balance sheets of EnLink Midstream, LLC and subsidiaries (the Company) as of December 31, 2020 and 2019, the related consolidated statements of operations, comprehensive loss, changes in members' equity, and cash flows for each of the years in the three-year period ended December 31, 2020, and the related notes (collectively, the consolidated financial statements). We also have audited the Company's internal control over financial reporting as of December 31, 2020, based on criteria established in *Internal Control – Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Company as of December 31, 2020 and 2019, and the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2020, in conformity with U.S. generally accepted accounting principles. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2020 based on criteria established in *Internal Control – Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

Change in Accounting Principle

As discussed in Note 2(p) to the consolidated financial statements, the Company has changed its method of accounting for leases in 2019 due to the adoption of Accounting Standards Codification 842, *Leases*.

Basis for Opinions

The Company's management is responsible for these consolidated financial statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying *Management's Report on Internal Control Over Financial Reporting*. Our responsibility is to express an opinion on the Company's consolidated financial statements and an opinion on the Company's internal control over financial reporting based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

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

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

Definition and Limitations of Internal Control Over Financial Reporting

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

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

Critical Audit Matter

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

Recoverability of the carrying value of property and equipment

As discussed in Note 2 to the consolidated financial statements, the property and equipment balance at December 31, 2020 was $6,652.1 million. The Company evaluates long-lived assets of identifiable business activities for potential impairment whenever events or changes in circumstances indicate that their carrying value may not be recoverable. The carrying amount of a long-lived asset is not recoverable when it exceeds the undiscounted sum of the future cash flows expected to result from the use and eventual disposition of the asset. 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. Based upon the analysis performed, the Company recognized impairment expense of $168.0 million during the first quarter of 2020 on property and equipment related to a certain asset group in the Louisiana reporting unit.

We identified the evaluation of the recoverability of the carrying value of property and equipment as a critical audit matter. A high degree of judgment was required in evaluating the estimated fair value of a certain asset group in the Louisiana reporting unit. The key assumptions of forecasted adjusted gross margins, discount rate, and terminal multiple were challenging to evaluate as the estimated fair value of the asset group was sensitive to minor changes in these key assumptions. Additionally, the forecasted adjusted gross margins were based on certain internally developed assumptions for which there is limited market information.

The following are the primary procedures we performed to address this critical audit matter. We evaluated the design and tested the operating effectiveness of certain internal controls over the Company’s long-lived asset impairment evaluation process including controls related to the development of forecasted adjusted gross margins, discount rate, and terminal multiple used to estimate the fair value of the asset group. We compared the Company’s historical cash flow forecasts to actual results to assess the Company’s ability to accurately forecast. We assessed the Company’s forecasted adjusted gross margins by comparing to historical results, active contracts, and third party forecasts of natural gas, crude oil, and condensate available to the asset group. We involved valuation professionals with specialized skills and knowledge, who assisted in:

- evaluating the Company’s selected discount rate by comparing it against a discount rate range that was independently developed using publicly available market data for comparable entities
- evaluating the Company’s selected terminal multiple by comparing it to publicly available market data.

/s/ KPMG LLP

We have served as the Company’s auditor since 2013.

Dallas, Texas
February 17, 2021

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

	December 31, 2020	December 31, 2019
ASSETS		
Current assets:		
Cash and cash equivalents	$ 39.6	$ 77.4
Accounts receivable:		
Trade, net of allowance for bad debt of $0.5 and $0.5, respectively	80.6	36.2
Accrued revenue and other	447.5	460.1
Fair value of derivative assets	25.0	12.9
Other current assets	58.7	57.8
Total current assets	651.4	644.4
Property and equipment, net of accumulated depreciation of $3,863.0 and $3,418.6, respectively	6,652.1	7,081.3
Intangible assets, net of accumulated amortization of $668.8 and $545.9, respectively	1,125.4	1,249.9
Goodwill	—	184.6
Investment in unconsolidated affiliates	41.6	43.1
Fair value of derivative assets	4.9	4.3
Other assets, net	75.5	128.2
Total assets	$ 8,550.9	$ 9,335.8
LIABILITIES AND MEMBERS' EQUITY		
Current liabilities:		
Accounts payable and drafts payable	$ 60.5	$ 70.6
Accounts payable to related party	1.0	1.1
Accrued gas, NGLs, condensate, and crude oil purchases	290.5	354.8
Fair value of derivative liabilities	37.1	14.4
Current maturities of long-term debt	349.8	—
Other current liabilities	149.1	206.2
Total current liabilities	888.0	647.1
Long-term debt	4,244.0	4,764.3
Asset retirement obligations	14.2	15.5
Other long-term liabilities	80.6	90.8
Deferred tax liability, net	108.6	—
Fair value of derivative liabilities	2.5	6.8
Redeemable non-controlling interest	—	5.2
Members' equity:		
Members' equity (489,381,149 and 487,791,612 units issued and outstanding, respectively)	1,508.8	2,135.5
Accumulated other comprehensive loss	(15.3)	(11.0)
Non-controlling interest	1,719.5	1,681.6
Total members' equity	3,213.0	3,806.1
Commitments and contingencies (Note 14)		
Total liabilities and members' equity	$ 8,550.9	$ 9,335.8

See accompanying notes to consolidated financial statements.

ENLINK MIDSTREAM, LLC AND SUBSIDIARIES
Consolidated Statements of Operations
(In millions, except per unit data)

	Year Ended December 31, 2020	2019	2018
Revenues:			
Product sales	$ 2,977.5	$ 5,030.1	$ 6,512.3
Product sales—related parties	—	—	41.0
Midstream services	938.3	1,008.4	763.3
Midstream services—related parties	—	—	377.2
Gain (loss) on derivative activity	(22.0)	14.4	5.2
Total revenues	3,893.8	6,052.9	7,699.0
Operating costs and expenses:			
Cost of sales, exclusive of operating expenses and depreciation and amortization (1)	2,388.5	4,392.5	6,008.0
Operating expenses	373.8	467.1	453.4
Depreciation and amortization	638.6	617.0	577.3
Impairments	362.8	1,133.5	365.8
(Gain) loss on disposition of assets	8.8	(1.9)	0.4
General and administrative	103.3	152.6	140.3
Loss on secured term loan receivable	—	52.9	—
Total operating costs and expenses	3,875.8	6,813.7	7,545.2
Operating income (loss)	18.0	(760.8)	153.8
Other income (expense):			
Interest expense, net of interest income	(223.3)	(216.0)	(182.3)
Gain on extinguishment of debt	32.0	—	—
Income (loss) from unconsolidated affiliates	0.6	(16.8)	13.3
Other income	0.3	0.9	0.6
Total other expense	(190.4)	(231.9)	(168.4)
Loss before non-controlling interest and income taxes	(172.4)	(992.7)	(14.6)
Income tax expense	(143.2)	(6.9)	(18.2)
Net loss	(315.6)	(999.6)	(32.8)
Net income (loss) attributable to non-controlling interest	105.9	119.7	(19.6)
Net loss attributable to ENLC	$ (421.5)	$ (1,119.3)	$ (13.2)
Net loss attributable to ENLC per unit:			
Basic common unit	$ (0.86)	$ (2.41)	$ (0.07)
Diluted common unit	$ (0.86)	$ (2.41)	$ (0.07)

(1) Includes related party cost of sales of $8.7 million, $21.7 million, and $114.1 million for the years ended December 31, 2020, 2019, and 2018, respectively, and excludes all operating expenses as well as depreciation and amortization related to our operating segments of $631.3 million, $608.6 million, and $568.6 million for the years ended December 31, 2020, 2019, and 2018, respectively.

See accompanying notes to consolidated financial statements.

ENLINK MIDSTREAM, LLC AND SUBSIDIARIES
Consolidated Statements of Comprehensive loss
(In millions)

	Year Ended December 31,		
	2020	2019	2018
Net loss	$ (315.6)	$ (999.6)	$ (32.8)
Loss on designated cash flow hedge (1)	(4.3)	(9.0)	—
Comprehensive loss	(319.9)	(1,008.6)	(32.8)
Comprehensive income (loss) attributable to non-controlling interest	105.9	119.7	(19.6)
Comprehensive loss attributable to ENLC	$ (425.8)	$ (1,128.3)	$ (13.2)

(1) The loss on designated cash flow hedge recorded in accumulated other comprehensive loss for the years ended December 31, 2020 and 2019 was net of a tax benefit of $ 1.3 million and $3.4 million, respectively

See accompanying notes to consolidated financial statements.

ENLINK MIDSTREAM, LLC AND SUBSIDIARIES
Consolidated Statements of Changes in Members' Equity
(In millions)

	Common Units		Accumulated Other Comprehensive Loss	Non-Controlling Interest	Total	Redeemable Non-controlling interest (Temporary Equity)
	$	Units	$	$	$	$
Balance, December 31, 2017	$ 1,924.2	180.6	$ (2.0)	$ 3,634.5	$ 5,556.7	$ 4.6
Issuance of common units by ENLK	—	—	—	46.1	46.1	—
Conversion of restricted units for common units, net of units withheld for taxes	(5.7)	0.7	—	(5.6)	(11.3)	—
Unit-based compensation	20.5	—	—	21.4	41.9	—
Change in equity due to issuance of units by ENLK	0.7	—	—	(0.6)	0.1	—
Contributions from non-controlling interests	—	—	—	90.2	90.2	—
Distributions	(194.8)	—	—	(517.2)	(712.0)	—
Fair value adjustment related to redeemable non-controlling interest	(0.8)	—	—	(3.3)	(4.1)	4.1
Net income (loss)	(13.2)	—	—	(20.2)	(33.4)	0.6
Balance, December 31, 2018	1,730.9	181.3	(2.0)	3,245.3	4,974.2	9.3
Adoption of ASC 842	0.3	—	—	—	0.3	—
Balance, January 1, 2019	1,731.2	181.3	(2.0)	3,245.3	4,974.5	9.3
Issuance of common units for ENLK public common units related to the Merger	1,958.1	304.9	—	(1,559.1)	399.0	—
Conversion of restricted units for common units, net of units withheld for taxes	(7.8)	1.6	—	(2.8)	(10.6)	—
Unit-based compensation	37.5	—	—	1.4	38.9	—
Contributions from non-controlling interests	—	—	—	97.5	97.5	—
Distributions	(467.2)	—	—	(220.2)	(687.4)	(0.3)
Loss on designated cash flow hedge (1)	—	—	(9.0)	—	(9.0)	—
Fair value adjustment related to redeemable non-controlling interest	3.0	—	—	—	3.0	(4.0)
Net income (loss)	(1,119.3)	—	—	119.5	(999.8)	0.2
Balance, December 31, 2019	$ 2,135.5	487.8	$ (11.0)	$ 1,681.6	$ 3,806.1	$ 5.2

(1) Includes a tax benefit of $3.4 million.

See accompanying notes to consolidated financial statements.

ENLINK MIDSTREAM, LLC AND SUBSIDIARIES
Consolidated Statements of Changes in Members' Equity (Continued)
(In millions)

	Common Units		Accumulated Other Comprehensive Loss	Non-Controlling Interest	Total	Redeemable Non-controlling interest (Temporary Equity)
	$	Units	$	$	$	$
Balance, December 31, 2019	$ 2,135.5	487.8	$ (11.0)	$ 1,681.6	$ 3,806.1	$ 5.2
Conversion of restricted units for common units, net of units withheld for taxes	(4.7)	2.0	—	—	(4.7)	—
Unit-based compensation	33.0	—	—	—	33.0	—
Contributions from non-controlling interests	—	—	—	52.6	52.6	—
Distributions	(232.7)	—	—	(120.6)	(353.3)	(0.6)
Loss on designated cash flow hedge (1)	—	—	(4.3)	—	(4.3)	—
Fair value adjustment related to redeemable non-controlling interest	0.4	—	—	—	0.4	(0.6)
Redemption of non-controlling interest	—	—	—	—	—	(4.0)
Common units repurchased	(1.2)	(0.4)	—	—	(1.2)	—
Net income (loss)	(421.5)	—	—	105.9	(315.6)	—
Balance, December 31, 2020	$ 1,508.8	489.4	$ (15.3)	$ 1,719.5	$ 3,213.0	$ —

(1) Includes a tax benefit of $1.3 million.

See accompanying notes to consolidated financial statements.

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

	Year Ended December 31,		
	2020	**2019**	**2018**
Cash flows from operating activities:			
Net loss	$ (315.6)	$ (999.6)	$ (32.8)
Adjustments to reconcile net loss to net cash provided by operating activities:			
Impairments	362.8	1,133.5	365.8
Depreciation and amortization	638.6	617.0	577.3
Loss on secured term loan receivable	—	52.9	—
Non-cash revenue from contract restructuring	—	—	(45.5)
(Gain) loss on disposition of assets	8.8	(1.9)	0.4
Non-cash unit-based compensation	28.4	39.4	41.1
Payments to terminate interest rate swaps	(10.9)	—	—
Deferred tax expense	142.1	6.9	16.3
(Gain) loss on derivative activity recognized in net loss	22.0	(14.4)	(5.2)
Cash settlements on derivatives	(7.2)	16.9	(7.0)
Gain on extinguishment of debt	(32.0)	—	—
Amortization of debt issuance costs, net (premium) discount of notes	4.6	4.9	4.3
Distribution of earnings from unconsolidated affiliates	1.6	16.5	15.8
(Income) loss from unconsolidated affiliates	(0.6)	16.8	(13.3)
Other operating activities	(0.3)	(2.2)	(2.6)
Changes in assets and liabilities:			
Accounts receivable, accrued revenue, and other	(21.5)	337.1	(113.1)
Natural gas and NGLs inventory, prepaid expenses, and other	15.1	13.6	(12.2)
Accounts payable, accrued product purchases, and other accrued liabilities	(104.8)	(245.5)	58.3
Net cash provided by operating activities	731.1	991.9	847.6
Cash flows from investing activities:			
Additions to property and equipment	(302.2)	(754.9)	(843.1)
Acquisition of assets	(32.3)	—	—
Proceeds from sale of property	17.6	14.3	1.9
Distribution from unconsolidated affiliates in excess of earnings	0.5	3.7	6.9
Other investing activities	(1.3)	(4.6)	8.0
Net cash used in investing activities	(317.7)	(741.5)	(826.3)
Cash flows from financing activities:			
Proceeds from borrowings	1,650.0	3,310.0	3,946.8
Payments on borrowings	(1,786.0)	(2,971.4)	(3,060.0)
Payment of installment payable for EOGP acquisition	—	—	(250.0)
Debt financing costs	(7.7)	(10.0)	(1.9)
Distributions to non-controlling interests	(121.2)	(220.5)	(517.2)
Distribution to members	(232.7)	(467.2)	(194.8)
Conversion of restricted units, net of units withheld for taxes	(4.7)	(7.8)	(5.7)
Proceeds from issuance of ENLK common units	—	—	46.1
Contributions by non-controlling interests	52.6	97.5	90.2
Common unit repurchases	(1.2)	—	—
Other financing activities	(0.3)	(4.0)	(5.6)
Net cash provided by (used in) financing activities	(451.2)	(273.4)	47.9
Net increase (decrease) in cash and cash equivalents	(37.8)	(23.0)	69.2
Cash and cash equivalents, beginning of period	77.4	100.4	31.2
Cash and cash equivalents, end of period	$ 39.6	$ 77.4	$ 100.4

See accompanying notes to consolidated financial statements.

(1) Organization and Summary of Significant Agreements

(a) Organization of Business

ENLC is a Delaware limited liability company formed in October 2013. The Company's common units are traded on the New York Stock Exchange under the symbol "ENLC." ENLC owns all of ENLK's common units and also owns all of the membership interests of the General Partner. ENLK is a Delaware limited partnership formed in 2002. EnLink Midstream GP, LLC, a Delaware limited liability company and our wholly-owned subsidiary, is ENLK's general partner. The General Partner manages ENLK's operations and activities.

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 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, which, as of the closing date, amounted to 100% of the outstanding limited liability company interests in the Managing Member 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, (ii) ENLC, and (iii) ENLK, as a result of ENLC's ownership of the 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 the issuance of 304,822,035 ENLC common units.

- The 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—Certain Provisions of the Partnership Agreement" 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 ENLK's 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, we 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.

- We were required to allocate the goodwill in our Corporate reporting unit previously associated with the incentive distribution rights in ENLK granted to the General Partner which were created in connection with the Devon Transaction, to the Permian, Louisiana, Oklahoma, and North Texas reporting units. See "Note 3—Goodwill and Intangible Assets" for more information on this transaction.

- We reduced our deferred tax liability by $399.0 million related to ENLC's step-up in basis of ENLK's underlying assets with the offsetting credit in members' equity. See "Note 7—Income Taxes" for more information on the deferred tax liabilities.

(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 brine disposal services.

Our midstream energy asset network includes approximately 11,900 miles of pipelines, 22 natural gas processing plants with approximately 5.5 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, or barge, truck, or rail terminal.

(c) Current Market Environment

On March 11, 2020, the World Health Organization declared the ongoing coronavirus (COVID-19) outbreak a pandemic and recommended containment and mitigation measures worldwide. The ongoing pandemic has reached every region of the globe and has resulted in widespread adverse impacts on the global economy, on the energy industry as a whole and on midstream companies, and on our customers, suppliers, and other parties with whom we have business relations. The pandemic and related travel and operational restrictions, as well as business closures and curtailed consumer activity, have resulted in a reduction in global demand for energy, volatility in the market prices for crude oil, condensate, natural gas and NGLs, and a significant reduction in the market price of crude oil during the first half of 2020. As a result of the demand destruction, reduced commodity prices, and an uncertain timeline for full recovery, many oil and natural gas producers, including some of our customers, curtailed their current drilling and production activity and reduced or slowed down their plans for future drilling and production activity. As a result of these decreases in producer activity, we experienced reduced volumes gathered, processed, fractionated, and transported on our assets in some of the regions that supply our systems during the first half of 2020. Although volumes have since been restored nearly to pre-pandemic levels, capital investments by oil and natural gas producers remain at low levels.

There is considerable uncertainty regarding how long the COVID-19 pandemic will persist and affect economic conditions and the extent and duration of changes in consumer behavior, such as the reluctance to travel, as well as whether governmental and other measures implemented to try to slow the spread of the virus, such as large-scale travel bans and restrictions, border closures, quarantines, shelter-in-place orders, and business and government shutdowns that exist as of the date of this report will be extended or whether new measures will be imposed. A sustained significant decline in oil and natural gas exploration and production activities and related reduced demand for our services by our customers, whether due to decreases in consumer demand or reduction in the prices for oil, condensate natural gas and NGLs or otherwise, would have a material adverse effect on our business, liquidity, financial condition, results of operations, and cash flows (including our ability to make distributions to our unitholders).

(2) Significant Accounting Policies

(a) Basis of Presentation

The accompanying consolidated financial statements have been prepared in accordance with GAAP. 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.

Evaluation of Our Contractual Performance Obligations

Performance obligations in our contracts with customers 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). 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. 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.

Accounting Methodology for Certain Contracts

For NGL contracts in which we purchase raw mix NGLs and subsequently transport, fractionate, and market the NGLs, we consider the contractually-stated fees to serve as pricing mechanisms that reduce the cost of the commodities purchased. We account for the contractually-stated fees on the consolidated statements of operations as a reduction of cost of sales of such commodities purchased upon receipt of the raw mix NGLs, because 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. 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 as outlined above for NGL contracts.

For our natural gas gathering and processing contracts in which we perform midstream services and also purchase the natural gas, we 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, net of fees.

- 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.

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.

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.

Satisfaction of Performance Obligations and Recognition of Revenue

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. 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. We 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.

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. Prior to issuing our financial statements, we review our revenue and purchases estimates based on available information to determine if adjustments are required. 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, 2020, we had contractual commitments of $174.3 million under our MVC contracts and recorded $57.2 million of revenue due to volume shortfalls.

MVC and Firm Transportation Commitments (in millions) (1)	
2021	$ 121.1
2022	102.4
2023	91.5
2024	77.4
2025	34.8
Thereafter	110.1
Total	$ 537.3

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

(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 $6.1 million and $5.7 million at December 31, 2020 and 2019, respectively, which approximate the fair value of these imbalances. We had imbalance receivables of $7.5 million and $6.4 million at December 31, 2020 and 2019, 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

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. Routine repairs and maintenance are charged against income when incurred. Renewals and improvements that extend the useful life or improve the function 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,	
	2020	2019
Transmission assets	$ 1,410.5	$ 1,376.5
Gathering systems	4,782.9	4,856.5
Gas processing plants	4,082.1	3,862.2
Other property and equipment	161.0	188.0
Construction in process	78.6	216.7
Property and equipment	10,515.1	10,499.9
Accumulated depreciation	(3,863.0)	(3,418.6)
Property and equipment, net of accumulated depreciation	$ 6,652.1	$ 7,081.3

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 - 25 years

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 consolidated statements of operations. For the year ended December 31, 2020, we disposed of assets with a net book value of $36.4 million, and these dispositions primarily related to the sale of certain non-core assets. This decrease in book value was offset by $27.6 million of proceeds from the sale of property, resulting in a $8.8 million loss on disposition of assets in the consolidated statements of operations for the year ended December 31, 2020.

For the year ended December 31, 2019, we disposed of assets with a net book value of $12.4 million. 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 $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.

Impairment Review. In accordance with ASC 360, *Property, Plant, and Equipment*, we evaluate long-lived assets of identifiable business activities for potential impairment whenever events or changes in circumstances indicate that their carrying value may not be recoverable. The carrying amount of a long-lived asset is not recoverable when it exceeds the undiscounted sum of the future cash flows expected to result from the use and eventual disposition of the asset. Estimates of expected future cash flows represent management's best estimate based on reasonable and supportable assumptions. When the carrying amount of a long-lived asset is not recoverable, an impairment 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, 2020, we recognized a $168.0 million impairment on property and equipment related to a portion of our Louisiana reporting segment because the carrying amounts were not recoverable based on our expected future cash flows, and $3.4 million of impairments related to certain cancelled projects.

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.

(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. For additional information about the effect of financial instruments on comprehensive income (loss), see "Note 12—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 10—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, 2020, 2019, and 2018 relate to the Series B Preferred Units, the Series C Preferred Units, 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. For periods prior to the Merger, our non-controlling interests also included ENLK's public common unitholders.

(m) Goodwill

Goodwill is the cost of an acquisition less the fair value of the net identifiable assets of the acquired business. We evaluated goodwill for impairment annually as of October 31 and whenever events or changes in circumstances indicated it was more likely than not that the fair value of a reporting unit was less than its carrying amount. For additional information regarding our previous assessments 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 ten to twenty years. In accordance with ASC 350, *Intangibles—Goodwill and Other*, we evaluate intangibles for potential impairment whenever events or changes in circumstances indicate that their carrying value may not be recoverable. 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) Leases

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.

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. For more information, see "Note 5—Leases."

(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 to hedge variability in interest rates and effectively lock in the benchmark interest rate at the inception of the swap.

In April 2019, we entered into $850.0 million of interest rate swaps 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 these interest rate swap contracts 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 swaps into interest expense from accumulated other comprehensive income (loss). There is no ineffectiveness related to this hedge. In December 2020, in connection with the partial repayment of the Term Loan, we terminated $500.0 million of the $850.0 million interest rate swaps and settled the outstanding derivative liability of $10.9 million. For additional information, see "Note 12—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 adjusted gross 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,		
	2020	2019	2018
Devon	14.4 %	10.5 %	10.4 %
Dow Hydrocarbons and Resources LLC	13.2 %	10.0 %	11.1 %
Marathon Petroleum Corporation	12.2 %	13.8 %	11.5 %

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. As of December 31, 2020 and 2019, we had a reserve for uncollectible receivables of $0.5 million for each period, 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. Environmental expenditures were not material for the years ended December 31, 2020, 2019, and 2018.

(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 the General Partner is recorded by ENLK since ENLC has no substantial or managed operating activities other than its interests in ENLK. For additional information, see "Note 11—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 14—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 $32.6 million and $29.8 million as of December 31, 2020 and 2019, 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 purchase 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 interests are not considered to be a component of members’ equity and are 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). When the redemption feature is exercised the redemption value of the non-controlling interest is reclassified to a liability on the consolidated balance sheets.

During the first quarter of 2020, the non-controlling interest holder in one of our non-wholly owned subsidiaries exercised its option to require us to purchase its remaining interest. We have recorded an estimated $4.0 million related to the redemption of the non-controlling interest included in “Other current liabilities” on the consolidated balance sheet as of December 31, 2020, but we have not yet agreed to a redemption value with the non-controlling interest holder.

(x) Adopted Accounting Standards

Effective January 1, 2020, we adopted 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. To the extent 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.” The amortization related to cloud computing arrangements was not material for the year ended December 31, 2020.

Effective January 1, 2020, we adopted ASU 2016-13, Financial Instruments—Credit Losses (Topic 326). The updates in ASU 2016-13 provide financial statement users with more information about the expected credit losses on financial instruments and other commitments to extend credit held by a reporting entity at each reporting date. Following the adoption of ASU 2016-13, we record an allowance for doubtful accounts based on our expectation of future losses. Because our receivables are typically paid within 30 days, and because we closely monitor the credit-worthiness of all our counterparties, adopting ASU 2016-13 did not have a material effect on our financial statements. However, in the event we foresee further or sustained deterioration in the current market environment, or other factors indicating an increased likelihood of defaults by our customers, we may recognize additional losses.

(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. For the years ended December 31, 2020, 2019, and 2018, we evaluated goodwill for impairment annually as of October 31 and whenever events or changes in circumstances indicated it is more likely than not that the fair value of a reporting unit was less than its carrying amount. We first assessed qualitative factors to evaluate whether it was more likely than not that the fair value of a reporting unit was less than its carrying amount as the basis for determining whether it was necessary to perform a goodwill impairment test. We may have elected to perform a goodwill impairment test without completing a qualitative assessment.

We performed our goodwill assessments at the reporting unit level for all reporting units. We used a discounted cash flow analysis to perform the assessments. Key assumptions in the analysis included 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 incorporated current and historical market and financial information, among other factors. Impairment determinations involved significant assumptions and judgments, and differing assumptions regarding any of these inputs could have had a significant effect on the various valuations. If actual results were not consistent with our assumptions and estimates, or our assumptions and estimates changed due to new information, we may have been exposed to goodwill impairment charges, which would have been recognized in the period in which the carrying value exceeded fair value.

The tables below provide a summary of our change in carrying amount of goodwill by segment (in millions) for the years ended December 31, 2020, 2019, and 2018 by assigned reporting unit.

	Permian	Louisiana	Oklahoma	North Texas	Corporate	Totals
Year Ended December 31, 2020						
Balance, beginning of period	$ 184.6	$ —	$ —	$ —	$ —	$ 184.6
Impairment	(184.6)	—	—	—	—	(184.6)
Balance, end of period	$ —	$ —	$ —	$ —	$ —	$ —

	Permian	Louisiana	Oklahoma	North Texas	Corporate	Totals
Year Ended December 31, 2019						
Balance, beginning of period	$ —	$ —	$ 190.3	$ —	$ 1,119.9	$ 1,310.2
Goodwill allocation	184.6	186.5	623.1	125.7	(1,119.9)	—
Impairment	—	(186.5)	(813.4)	(125.7)	—	(1,125.6)
Balance, end of period	$ 184.6	$ —	$ —	$ —	$ —	$ 184.6

	Permian	Louisiana	Oklahoma	North Texas	Corporate	Totals
Year Ended December 31, 2018						
Balance, beginning of period	$ 29.3	$ —	$ 190.3	$ 202.7	$ 1,119.9	$ 1,542.2
Impairment	(29.3)	—	—	(202.7)	—	(232.0)
Balance, end of period	$ —	$ —	$ 190.3	$ —	$ 1,119.9	$ 1,310.2

Goodwill Impairment Analysis for the Year Ended December 31, 2020

During the first quarter of 2020, we determined that a sustained decline in our unit price and weakness in the overall energy sector, driven by low commodity prices and lower consumer demand due to the COVID-19 pandemic, caused a change in circumstances warranting an interim impairment test. Based on these triggering events, we performed a quantitative goodwill impairment analysis on the remaining goodwill in the Permian reporting unit. Based on this analysis, a goodwill impairment loss for our Permian reporting unit in the amount of $184.6 million was recognized as an impairment loss on the consolidated statement of operations for the year ended December 31, 2020. As a result of this impairment loss, we have no goodwill remaining as of December 31, 2020.

Goodwill Impairment Analysis for the Year Ended December 31, 2019

During the first quarter of 2019, we recognized a $186.5 million goodwill impairment related to goodwill that had been reallocated from our Corporate reporting unit to our Louisiana reporting unit as a result of the Merger.

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 our common unit price and the expected reduction in our 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 $125.7 million and $813.4 million in our North Texas and Oklahoma reporting units, respectively. These amounts are included in impairments in the consolidated statement of operations for the year ended December 31, 2019. The goodwill for our North Texas and Oklahoma reporting units primarily related to the goodwill reallocated from our Corporate reporting unit as a result of the Merger in January 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.

Intangible Assets

Intangible assets associated with customer relationships are amortized on a straight-line basis over the expected period of benefits of the customer relationships, which range from 10 to 20 years.

The following table represents our change in carrying value of intangible assets for the periods stated (in millions):

	Gross Carrying Amount	Accumulated Amortization	Net Carrying Amount
Year Ended December 31, 2020			
Customer relationships, beginning of period	$ 1,795.8	$ (545.9)	$ 1,249.9
Amortization expense	—	(123.5)	(123.5)
Retirements (1)	(1.6)	0.6	(1.0)
Customer relationships, end of period	$ 1,794.2	$ (668.8)	$ 1,125.4
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

(1) Intangible assets retired as a result of the disposition of certain non-core assets.

The weighted average amortization period for intangible assets is15.0 years. Amortization expense was $123.5 million, $123.7 million, and $123.5 million for the years ended December 31, 2020, 2019, and 2018, respectively.

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

2021	$ 123.4
2022	123.4
2023	123.4
2024	123.4
2025	106.1
Thereafter	525.7
Total	$ 1,125.4

(4) Related Party Transactions

(a) Transactions with Cedar Cove JV

For the year ended December 31, 2018, we recorded service revenue of $0.5 million as "Midstream services—related parties" on the consolidated statements of operations. Additionally, for the years ended December 31, 2020, 2019, and 2018, we recorded cost of sales, exclusive of operating cost and depreciation and amortization related to our operating segments of $8.7 million, $21.7 million, $44.1 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 for the years ended December 31, 2020 and 2019, respectively. We had an accounts payable balance related to transactions with the Cedar Cove JV of $1.0 million and $1.1 million at December 31, 2020 and 2019, respectively.

(b) Transactions with GIP

For the year ended December 31, 2020, we recorded general and administrative expenses of $0.2 million related to personnel secondment services provided by GIP. Expenses related to transactions with GIP were not material for the years ended December 31, 2019 and 2018.

(c) Transactions with ENLK

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.

Reimbursement of Expenses. Prior to the Merger, we paid ENLK $2.5 million during the year ended December 31, 2018 as reimbursement of ENLC's portion of administrative and compensation costs for officers and employees that performed services for ENLC. Officers and employees that performed services for us 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 ENLK 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.

(d) Transactions with Devon

On July 18, 2018, subsidiaries of Devon sold all of their equity interests in ENLK, ENLC, and the Managing Member 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 year ended December 31, 2018, related party revenues from Devon accounted for 5.4% of our revenues.

Gathering and Processing Agreements with Devon

On January 1, 2014, we entered into 10-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, 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, we recognized $321.3 million of revenue 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. 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 of our combined revenues from January 1, 2018 to July 18, 2018.

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 of our combined revenue from January 1, 2018 to July 18, 2018.

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 of service revenues from January 1, 2018 to July 18, 2018.

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 of our combined revenues from January 1, 2018 to July 18, 2018.

(e) Tax Sharing Agreement

We, ENLK, 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, we incurred approximately $0.4 million 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

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 $57.6 million of our lease liability and $32.4 million of our right-of-use asset as of December 31, 2020. Our office leases represented $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 $14.6 million of our lease liability and $14.6 million of our right-of-use asset as of December 31, 2020. Compression and other field equipment rentals represented $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.

- *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 $15.1 million of our lease liability and $12.5 million of our right-of-use asset as of December 31, 2020. Land and land easement leases represented $15.3 million of our lease liability and $12.9 million of our right-of-use asset as of December 31, 2019.

- *Other.* We rent office equipment and other items that represent $0.3 million of our lease liability and $0.3 million of our right-of-use asset as of December 31, 2020. Office equipment and other items represented $0.6 million of our lease liability and $0.6 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):

Operating leases:	**December 31, 2020**	**December 31, 2019**
Other assets, net	$ 59.8	$ 80.4
Other current liabilities	$ 16.3	$ 21.1
Other long-term liabilities	$ 71.3	$ 81.9

Other lease information		
Weighted-average remaining lease term—Operating leases	11.1 years	10.6 years
Weighted-average discount rate—Operating leases	5.1 %	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. Impairments of right-of-use assets are recognized in “Impairments” on the consolidated statements of operations. The components of total lease expense are as follows (in millions):

	Year Ended December 31,	
	2020	**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	23.1	28.7
Short-term lease expense	22.1	32.0
Variable lease expense	11.8	7.7
Impairments	6.8	—
Total lease expense	$ 63.8	$ 68.4

During the fourth quarter of 2020, we determined that we would cease using a portion of our Dallas, Houston, and Midland offices. We are attempting to sublease the vacated space; however, as we believe the terms of a sublease would be below our current rental rates, we evaluated the related right-of-use assets for impairment by comparing the estimated fair values of the right-of-use assets to their carrying values. Estimated fair values were calculated using a discounted cash flow analysis that utilized Level 3 inputs, which included estimated future cash flows and a discount rate derived from market data. As the carrying value of each right-of-use asset exceeded its estimated fair value, we recognized impairment expense of $6.8 million for the year ended December 31, 2020.

The following table summarizes the maturity of our lease liability as of December 31, 2020 (in millions):

	Total	**2021**	**2022**	**2023**	**2024**	**2025**	**Thereafter**
Undiscounted operating lease liability	$ 121.7	$ 19.6	$ 13.7	$ 10.2	$ 9.5	$ 9.8	$ 58.9
Reduction due to present value	(34.1)	(4.0)	(3.6)	(3.2)	(2.8)	(2.4)	(18.1)
Operating lease liability	$ 87.6	$ 15.6	$ 10.1	$ 7.0	$ 6.7	$ 7.4	$ 40.8

(6) Long-Term Debt

As of December 31, 2020 and 2019, long-term debt consisted of the following (in millions):

	December 31, 2020			December 31, 2019		
	Outstanding Principal	Premium (Discount)	Long-Term Debt	Outstanding Principal	Premium (Discount)	Long-Term Debt
AR Facility due 2023 (1)	$ 250.0	$ —	$ 250.0	$ —	$ —	$ —
Consolidated Credit Facility due 2024 (2)	—	—	—	350.0	—	350.0
Term Loan due 2021 (3)	350.0	—	350.0	850.0	—	850.0
ENLK's 4.40% Senior unsecured notes due 2024	521.8	1.1	522.9	550.0	1.5	551.5
ENLK's 4.15% Senior unsecured notes due 2025	720.8	(0.6)	720.2	750.0	(0.7)	749.3
ENLK's 4.85% Senior unsecured notes due 2026	491.0	(0.4)	490.6	500.0	(0.5)	499.5
ENLC's 5.625% Senior unsecured notes due 2028	500.0	—	500.0	—	—	—
ENLC's 5.375% Senior unsecured notes due 2029	498.7	—	498.7	500.0	—	500.0
ENLK's 5.60% Senior unsecured notes due 2044	350.0	(0.2)	349.8	350.0	(0.2)	349.8
ENLK's 5.05% Senior unsecured notes due 2045	450.0	(5.7)	444.3	450.0	(5.9)	444.1
ENLK's 5.45% Senior unsecured notes due 2047	500.0	(0.1)	499.9	500.0	(0.1)	499.9
Debt, long-term and current maturities	$ 4,632.3	$ (5.9)	4,626.4	$ 4,800.0	$ (5.9)	4,794.1
Debt issuance cost (4)			(32.6)			(29.8)
Less: Current maturities of long-term debt (3)			(349.8)			—
Long-term debt, net of unamortized issuance cost			$ 4,244.0			$ 4,764.3

(1) Bears interest based on LMIR and/or LIBOR plus an applicable margin. The effective interest rate was 2.0% at December 31, 2020.
(2) Bears interest based on Prime and/or LIBOR plus an applicable margin. The effective interest rate was 3.3% at December 31, 2019.
(3) Bears interest based on Prime and/or LIBOR plus an applicable margin. The effective interest rate was 1.7% and 3.2% at December 31, 2020 and 2019, respectively. The Term Loan will mature on December 10, 2021. 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, 2020.
(4) Net of accumulated amortization of $14.1 million and $10.9 million at December 31, 2020 and 2019, respectively.

Maturities

Maturities for the long-term debt as of December 31, 2020 are as follows (in millions):

2021	$ 350.0
2022	—
2023	250.0
2024	521.8
2025	720.8
Thereafter	2,789.7
Subtotal	4,632.3
Less: net discount	(5.9)
Less: debt issuance cost	(32.6)
Less: current maturities of long-term debt	(349.8)
Long-term debt, net of unamortized issuance cost	$ 4,244.0

AR Facility

On October 21, 2020, EnLink Midstream Funding, LLC, a bankruptcy-remote special purpose entity that is an indirect subsidiary of ENLC (the "SPV") entered into the AR Facility to borrow up to $250.0 million. In connection with the AR Facility, certain subsidiaries of ENLC have sold and contributed, and will continue to sell or contribute, their accounts receivable to the SPV to be held as collateral for borrowings under the AR Facility. The SPV's assets are not available to satisfy the obligations of ENLC or any of its affiliates.

Since our investment in the SPV is not sufficient to finance its activities without additional support from us, the SPV is a variable interest entity. We are the primary beneficiary of the SPV because we have the power to direct the activities that most significantly affect its economic performance and we are obligated to absorb its losses or receive its benefits from operations. Since we are the primary beneficiary of the SPV, we consolidate its assets and liabilities, which consist of billed and unbilled accounts receivable of $279.7 million and long-term debt of $250.0 million.

The amount available for borrowings at any one time under the AR Facility is limited to a borrowing base amount calculated based on the outstanding balance of eligible receivables held as collateral, subject to certain reserves, concentration limits, and other limitations. Borrowings under the AR Facility bear interest (based on LIBOR or LMIR (as defined in the AR Facility)), in each case subject to a minimum floor of 0.375% plus a drawn fee initially in the amount of 1.625%. The drawn fee varies based on ENLC's credit rating, and the SPV also pays a fee on the undrawn committed amount of the AR Facility. Interest and fees payable by the SPV under the AR Facility are due monthly.

The AR Facility is scheduled to terminate on October 20, 2023, unless extended in accordance with its terms or earlier terminated, at which time no further advances will be available and the obligations under the AR Facility must be repaid in full by no later than (i) the date that is ninety (90) days following such date or (ii) such earlier date on which the loans under the AR Facility become due and payable.

The AR Facility includes covenants, indemnification provisions, and events of default, including those providing for termination of the AR Facility and the acceleration of amounts owed by the SPV under the AR Facility if, among other things, a borrowing base deficiency exists, there is an event of default under the Consolidated Credit Facility, the Term Loan or certain other indebtedness, certain events negatively affecting the overall credit quality of the receivables held as collateral occur, a change of control occurs, or if the consolidated leverage ratio of ENLC exceeds limits identical to those in the Consolidated Credit Facility and the Term Loan.

At December 31, 2020, we were in compliance with and expect to be in compliance with the financial covenants of the AR Facility for at least the next twelve months.

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 and 105% of the outstanding letters of credit under the Consolidated Credit Facility ($22.2 million as of December 31, 2020). 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 from1.125% 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, 2020, we were in compliance with and expect to be in compliance with the financial covenants of the Consolidated Credit Facility for at least the next twelve months.

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. 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 $350.0 million as of December 31, 2020. 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 from1.0% 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 from0.0% 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, 2020, we were in compliance with and expect to be in compliance with the financial covenants of the Term Loan for at least the next twelve months.

Issuances and Redemptions 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.

On December 14, 2020, ENLC issued $500.0 million in aggregate principal amount of ENLC's 5.625% senior unsecured notes due January 15, 2028 (the "2028 Notes") at a price to the public of 100% of their face value. Interest payments on the 2028 Notes are payable on January 15 and July 15 of each year, beginning on July 15, 2021. The 2028 Notes are fully and unconditionally guaranteed by ENLK. Net proceeds of approximately $494.7 million were used to repay a portion of the borrowings under the Term Loan due December 2021.

All interest payments for senior unsecured notes are due semi-annually, in arrears.

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
2028 Notes	January 15, 2028	Prior to July 15, 2027	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 December 1, 2046	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.

The indenture governing the 2028 Notes provides that if a Change of Control Triggering Event (as defined in the indenture) occurs, ENLC must offer to repurchase the 2028 Notes at a price equal to 101% of the principal amount of the 2028 Notes, plus accrued and unpaid interest to, but excluding, the date of repurchase.

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, 2020, 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.

Senior Unsecured Notes Repurchases

For the year ended December 31, 2020, we and ENLK made aggregate payments to partially repurchase the 2024, 2025, 2026, and 2029 Notes in open market transactions. Activity related to the partial repurchases of our outstanding debt consisted of the following (in millions):

	Year Ended December 31, 2020
Debt repurchased	$ 67.7
Aggregate payments	(36.0)
Net discount on repurchased debt	(0.3)
Accrued interest on repurchased debt	0.6
Gain on extinguishment of debt	$ 32.0

(7) Income Taxes

The components of our income tax expense are as follows (in millions):

	Year Ended December 31,		
	2020	2019	2018
Current income tax expense	$ (1.1)	$ —	$ (1.9)
Deferred tax expense	(142.1)	(6.9)	(16.3)
Total income tax expense	$ (143.2)	$ (6.9)	$ (18.2)

The following schedule reconciles total income tax expense and the amount calculated by applying the statutory U.S. federal tax rate to income before income taxes (in millions):

	Year Ended December 31,		
	2020	2019	2018
Expected income tax benefit (expense) based on federal statutory tax rate	$ 58.5	$ 233.6	$ (1.0)
State income tax benefit (expense), net of federal benefit	6.5	27.0	(0.1)
Unit-based compensation (1)	(6.0)	(2.2)	(0.7)
Non-deductible expense related to impairments	(43.4)	(264.5)	(10.7)
Change in valuation allowance	(153.3)	—	—
Other	(5.5)	(0.8)	(5.7)
Total income tax expense	$ (143.2)	$ (6.9)	$ (18.2)

(1) Related to book-to-tax differences recorded upon the vesting of restricted incentive units.

Deferred Tax Assets and Liabilities

Deferred income taxes reflect the net tax effects of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for income tax purposes. The deferred tax liabilities, net of deferred tax assets, are included in "Deferred tax liability, net" in the consolidated balance sheet as of December 31, 2020. The deferred tax assets, net of deferred tax liabilities, are included in "Other assets, net" in the consolidated balance sheet at December 31, 2019. Our deferred income tax assets and liabilities as of December 31, 2020 and 2019 are as follows (in millions):

	December 31, 2020	December 31, 2019
Deferred income tax assets:		
Federal net operating loss carryforward	$ 488.3	$ 341.4
State net operating loss carryforward	61.0	44.8
Total deferred tax assets, gross	549.3	386.2
Valuation allowance	(153.3)	—
Total deferred tax assets, net of valuation allowance	396.0	386.2
Deferred tax liabilities:		
Property, plant, equipment, and intangible assets (1)	504.6	(354.0)
Total deferred tax liabilities	504.6	(354.0)
Deferred tax asset (liability), net	$ (108.6)	$ 32.2

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(1) Includes our investment in ENLK and primarily relates to differences between the book and tax bases of property and equipment.

As a result of the Merger, we acquired all issued and outstanding ENLK common units that were not already held by us or our subsidiaries in exchange for the issuance of ENLC common units. This was a taxable exchange to our unitholders, and we received a step-up in tax basis of the underlying assets acquired. In accordance with ASC 810, *Consolidation*, the step-up in our basis reduced our deferred tax liability by $399.0 million at the time of the Merger.

As of December 31, 2020, we had federal net operating loss carryforwards of $2.3 billion that represent a net deferred tax asset of $488.3 million. As of December 31, 2020, we had state net operating loss carryforwards of $1.1 billion that represent a net deferred tax asset of $61.0 million. These carryforwards will begin expiring in 2028 through 2040. Under the Tax Cut and Jobs Act of 2017, federal net operating losses incurred in 2018 and in future years may be carried forward indefinitely, but the deductibility of such federal net operating losses is limited.

A valuation allowance is established to reduce deferred tax assets if all, or some portion, of such assets will more than likely not be realized. Due to recent cumulative losses, a valuation allowance of $153.3 million was established as of December 31, 2020, and was primarily related to federal and state tax operating loss carryforwards for which we do not believe a tax benefit is more likely than not to be realized. We did not record a valuation allowance as of December 31, 2019. Management believes it is more likely than not that the company will realize the benefits of the deferred tax assets, net of valuation allowance, at December 31, 2020.

For the years ended December 31, 2020 and 2019, 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, 2020, tax years 2016 through 2020 remain subject to examination by various taxing authorities.

(8) Certain Provisions of the Partnership Agreement

(a) Issuance of ENLK Common Units

For the year ended December 31, 2018, ENLK 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). ENLK used the net proceeds for general partnership purposes. In connection with the announcement of the Merger, ENLK 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, ENLK issued an aggregate of 50,000,000 Series B Preferred Units representing ENLK 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 ENLK 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.

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 ENLK 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. 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).

A summary of the distribution activity relating to the Series B Preferred Units for the years ended December 31, 2020, 2019, and 2018 is provided below:

Declaration period	Distribution paid as additional Series B Preferred Units	Cash distribution (in millions)	Date paid/payable
2020			
First Quarter of 2020	149,371	$ 16.8	May 13, 2020
Second Quarter of 2020	149,745	$ 16.8	August 13, 2020
Third Quarter of 2020	150,119	$ 16.9	November 13, 2020
Fourth Quarter of 2020	150,494	$ 16.9	February 12, 2021
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

(c) Series C Preferred Units

In September 2017, ENLK issued 400,000 Series C Preferred Units representing ENLK limited partner interests at a price to the public of $1,000 per unit. The Series C Preferred Units represent perpetual equity interests in ENLK and, unlike ENLK's 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 ENLK's 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, ENLK may redeem, at ENLK's 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. ENLK may undertake multiple partial redemptions. In addition, at any time within 120 days after the conclusion of any review or appeal process instituted by ENLK following certain rating agency events, ENLK may redeem, at ENLK's 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 the General Partner out of legally available funds for such purpose. The initial distribution rate for the Series C Preferred Units from and including the date of original issue to, but not including, December 15, 2022 is 6.0% per annum. On and after December 15, 2022, distributions on the Series C Preferred Units will accumulate for each distribution period at a percentage of the $1,000 liquidation preference per unit equal to an annual floating rate of the three-month LIBOR plus a spread of 4.11%. For each of the years ended December 31, 2020, 2019, and 2018, ENLK made distributions of $24.0 million to the holders of Series C Preferred Units.

(d) ENLK Common Unit Distributions

Prior to the Merger, unless restricted by the terms of the ENLK Credit Facility and/or the indentures governing ENLK's senior unsecured notes, ENLK was required to make distributions of 100% of available cash, as defined in the partnership agreement, within45 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, the General Partner owned the general partner interest in ENLK and all incentive distribution rights in ENLK. The General Partner was entitled to receive incentive distributions if the amount ENLK distributed with respect to any quarter exceeded levels specified in its partnership agreement. Under the quarterly incentive distribution provisions, the General Partner was entitled to 13.0% of amounts ENLK distributed in excess of $0.25 per unit, 23.0% of the amounts ENLK distributed in excess of $0.3125 per unit, and 48.0% of amounts ENLK distributed in excess of $0.375 per unit. At the closing of the Merger, the 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

(e) Allocation of ENLK Income

Prior to the closing of the Merger and for the year ended December 31, 2018, net income (loss) was allocated to the General Partner in an amount equal to its incentive distribution rights as described in section "(e) ENLK Common Unit Distributions" above. The 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, the General Partner's incentive distribution rights in ENLK's were eliminated.

For the year ended December 31, 2018, the General Partner's share of net income (loss) 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 (loss) adjusted for ENLC's unit-based compensation specifically allocated to the General Partner. For the years ended December 31, 2020, 2019, and 2018, the net income (loss) allocated to the General Partner is as follows (in millions):

	Year Ended December 31,		
	2020	2019	2018
Income allocation for incentive distributions	$ —	$ —	$ 59.5
Unit-based compensation attributable to ENLC's restricted and performance units	(33.0)	(37.0)	(20.3)
General Partner share of net loss	(0.6)	(1.4)	(0.6)
General Partner interest in EOGP acquisition	—	2.4	27.5
General Partner interest in net income (loss)	$ (33.6)	$ (36.0)	$ 66.1

(9) Members' Equity

(a) Common Unit Repurchase Program

In November 2020, the board of directors of the Managing Member authorized a common unit repurchase program for the repurchase of up to $100 million of outstanding ENLC common units. The repurchases will be made, in accordance with applicable securities laws, from time to time in open market or private transactions and may be made pursuant to a trading plan meeting the requirements of Rule 10b5-1 under the Securities Exchange Act of 1934, as amended. The repurchases will depend on market conditions and may be discontinued at any time.

For the year ended December 31, 2020, ENLC repurchased 383,614 outstanding ENLC common units for an aggregate price of $1.2 million.

(b) Issuance of ENLC Common Units related to the Merger

In connection with the consummation of the Merger, we issued 304,822,035 ENLC common units in exchange for all of the outstanding ENLK common units not previously owned by us.

(c) ENLC Equity Distribution Agreement

On February 22, 2019, ENLC entered into the ENLC EDA with the ENLC Sales Agents to sell up to $400.0 million in aggregate gross sales of ENLC common units from time to time through an "at the market" equity offering program. Under the ENLC EDA, ENLC may also sell common units to any ENLC Sales Agent as principal for the ENLC Sales Agent's own account at a price agreed upon at the time of sale. ENLC has no obligation to sell any ENLC common units under the ENLC EDA and may at any time suspend solicitation and offers under the ENLC EDA. As of February 11, 2021, ENLC has not sold any common units under the ENLC EDA.

(d) Earnings Per Unit and Dilution Computations

As required under ASC 260, *Earnings Per Share*, unvested share-based payments that entitle employees to receive non-forfeitable distributions are considered participating securities for earnings per unit calculations. The following table reflects the computation of basic and diluted earnings per unit for the periods presented (in millions, except per unit amounts):

	Year Ended December 31,		
	2020	2019	2018
Distributed earnings allocated to:			
Common units (1)	$ 183.5	$ 479.0	$ 194.9
Unvested restricted units (1)	3.1	5.7	2.8
Total distributed earnings	$ 186.6	$ 484.7	$ 197.7
Undistributed income (loss) allocated to:			
Common units	$ (598.4)	$ (1,584.8)	$ (207.9)
Unvested restricted units	(9.7)	(19.2)	(3.0)
Total undistributed loss	$ (608.1)	$ (1,604.0)	$ (210.9)
Net loss allocated to:			
Common units	$ (414.9)	$ (1,105.8)	$ (13.0)
Unvested restricted units	(6.6)	(13.5)	(0.2)
Total net loss	$ (421.5)	$ (1,119.3)	$ (13.2)
Basic and diluted net loss per unit:			
Basic	$ (0.86)	$ (2.41)	$ (0.07)
Diluted	$ (0.86)	$ (2.41)	$ (0.07)

(1) Represents distribution activity consistent with the distribution activity table below.

There were 489.3 million, 463.9 million, and 181.1 million weighted average common units outstanding for the years ended December 31, 2020, 2019, and 2018, respectively. All common unit equivalents were antidilutive because a net loss existed for those periods.

All outstanding units were included in the computation of diluted earnings per unit and weighted based on the number of days such units were outstanding during the period presented.

(e) Distributions

A summary of our distribution activity relating to ENLC common units for the years ended December 31, 2020, 2019, and 2018, respectively, is provided below:

Declaration period	Distribution/unit		Date paid/payable
2020			
First Quarter of 2020	$	0.09375	May 13, 2020
Second Quarter of 2020	$	0.09375	August 13, 2020
Third Quarter of 2020	$	0.09375	November 13, 2020
Fourth Quarter of 2020	$	0.09375	February 12, 2021
2019			
First Quarter of 2019	$	0.279	May 14, 2019
Second Quarter of 2019	$	0.283	August 13, 2019
Third Quarter of 2019	$	0.283	November 13, 2019
Fourth Quarter of 2019	$	0.1875	February 13, 2020
2018			
First Quarter of 2018	$	0.263	May 15, 2018
Second Quarter of 2018	$	0.267	August 14, 2018
Third Quarter of 2018	$	0.271	November 14, 2018
Fourth Quarter of 2018	$	0.275	February 14, 2019

(10) Investment in Unconsolidated Affiliates

As of December 31, 2020, our unconsolidated investments consisted of a 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,		
	2020	2019	2018
GCF			
Distributions	$ 1.6	$ 19.2	$ 22.3
Equity in income	$ 3.0	$ 16.5	$ 15.8
Cedar Cove JV			
Contributions	$ —	$ —	$ 0.1
Distributions	$ 0.5	$ 1.0	$ 0.4
Equity in loss (1)	$ (2.4)	$ (33.3)	$ (2.5)
Total			
Contributions	$ —	$ —	$ 0.1
Distributions	$ 2.1	$ 20.2	$ 22.7
Equity in income (loss) (1)	$ 0.6	$ (16.8)	$ 13.3

(1) 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 of December 31, 2020 and 2019 (in millions):

	December 31, 2020	December 31, 2019
GCF	$ 40.6	$ 39.2
Cedar Cove JV	1.0	3.9
Total investment in unconsolidated affiliates	$ 41.6	$ 43.1

(11) 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 directors, officers, and employees of the General Partner is recorded by ENLK since ENLC has no substantial or managed operating activities other than its interests in ENLK.

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

	Year Ended December 31,		
	2020	2019	2018
Cost of unit-based compensation charged to general and administrative expense	$ 21.3	$ 32.7	$ 30.3
Cost of unit-based compensation charged to operating expense	7.1	6.7	10.8
Total unit-based compensation expense	$ 28.4	$ 39.4	$ 41.1
Non-controlling interest in unit-based compensation	$ —	$ 0.5	$ 15.7
Amount of related income tax benefit recognized in net loss (1)	$ 6.7	$ 9.1	$ 5.3

(1) For the years ended December 31, 2020, 2019, and 2018 the amount of related income tax expense recognized in net loss excluded $ 6.0 million, $2.2 million, and $0.7 million, respectively, related to book-to-tax differences recorded upon vesting of restricted units.

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) ENLC 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, 2020 is provided below:

	Year Ended December 31, 2020	
ENLC Restricted Incentive Units:	**Number of Units**	**Weighted Average Grant-Date Fair Value**
Non-vested, beginning of period	4,063,605	$ 13.85
Granted (1)	4,897,329	5.41
Vested (1)(2)	(2,880,968)	10.92
Forfeited	(729,880)	8.32
Non-vested, end of period	5,350,086	$ 8.45
Aggregate intrinsic value, end of period (in millions)	$ 19.8	

(1) Restricted incentive units typically vest at the end of three years. In February 2020, ENLC granted 1,144,842 restricted incentive units with a fair value of $5.2 million to officers and certain employees as bonus payments for 2019, and these restricted incentive units vested immediately and are included in the restricted incentive units granted and vested line items.
(2) Vested units included 1,020,412 units withheld for payroll taxes paid on behalf of employees.

A summary of the restricted incentive units' aggregate intrinsic value (market value at vesting date) and fair value of units vested (market value at date of grant) for the years ended December 31, 2020, 2019, and 2018 is provided below (in millions):

	Year Ended December 31,		
ENLC Restricted Incentive Units:	**2020**	**2019**	**2018**
Aggregate intrinsic value of units vested	$ 12.1	$ 17.3	$ 12.8
Fair value of units vested	$ 31.5	$ 22.8	$ 16.5

As of December 31, 2020, there were $30.0 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 2.1 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.

(c) ENLC 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.

Pre-2019 Performance Unit Awards

Performance awards granted prior to March 8, 2019 provided that the vesting of performance units granted 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. Prior to the Merger, vesting of the performance units was 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 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.

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 recognized 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.

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 (the "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 "Committee") of the 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 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 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 were eligible to vest (using linear interpolation) based on the Cash Flow performance of ENLC for the performance period ending December 31, 2020:

Performance Level	ENLC's Achieved Cash Flow	Vesting percentage of the Tranche CF Units
Below Threshold	Less than $1.345	0%
Threshold	Equal to $1.345	50%
Target	Equal to $1.494	100%
Maximum	Greater than or Equal to $1.643	200%

The following table sets out the levels at which the Tranche CF Units were 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:

ENLC Performance Units:	July 2020	March 2020	January 2020	October 2019	June 2019	March 2019	March 2018
Grant-date fair value	$ 2.33	$ 1.13	$ 7.69	$ 7.29	$ 9.92	$ 13.10	$ 21.63
Beginning TSR price	$ 2.52	$ 1.25	$ 6.13	$ 7.42	$ 9.84	$ 10.92	$ 16.55
Risk-free interest rate	0.17 %	0.42 %	1.62 %	1.44 %	1.72 %	2.42 %	2.38 %
Volatility factor	67.00 %	51.00 %	37.00 %	35.00 %	33.50 %	33.86 %	51.36 %

The following table presents a summary of the performance units:

	Year Ended December 31, 2020	
ENLC Performance Units:	Number of Units	Weighted Average Grant-Date Fair Value
Non-vested, beginning of period	1,317,856	$ 14.22
Granted	1,361,986	6.63
Vested (1)	(181,647)	30.31
Forfeited	(146,954)	10.30
Non-vested, end of period	2,351,241	$ 8.82
Aggregate intrinsic value, end of period (in millions)	$ 8.7	

(1) Vested units included 69,052 units withheld for payroll taxes paid on behalf of employees.

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, 2020, 2019, and 2018 is provided below (in millions).

	Year Ended December 31,		
ENLC Performance Units:	2020	2019	2018
Aggregate intrinsic value of units vested	$ 0.9	$ 3.4	$ 4.7
Fair value of units vested	$ 5.5	$ 7.9	$ 7.7

As of December 31, 2020, there were $10.5 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 1.3 years.

(d) ENLK Restricted Incentive Units

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 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 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 the closing of the Merger on January 25, 2019 under the GP Plan.

	Year Ended December 31,	
ENLK Restricted Incentive Units:	**2019**	**2018**
Aggregate intrinsic value of units vested	$ 8.0	$ 13.1
Fair value of units vested	$ 7.2	$ 16.4

(e) ENLK Performance Units

Prior to the Merger, the 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 TSR performance goals relative to the TSR achievement of 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 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 Peer Companies' securities; (iii) an estimated ranking of ENLK and ENLC among the Peer Companies; and (iv) the distribution yield. The fair value of the performance unit on the date of grant is expensed over a vesting period of approximately three years.

ENLK Performance Units:	**March 2018**
Grant-date fair value	$ 19.24
Beginning TSR price	$ 15.44
Risk-free interest rate	2.38 %
Volatility factor	43.85 %

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 the closing of the Merger on January 25, 2019 under the GP Plan.

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

(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. Contributions of $7.2 million, $9.4 million, and $8.3 million were made to the plan for the years ended December 31, 2020, 2019, and 2018, respectively.

(12) Derivatives

Interest Rate Swaps

In April 2019, we entered into $850.0 million of interest rate swaps 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 these interest rate swap contracts 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 swaps into interest expense from accumulated other comprehensive income (loss). There is no ineffectiveness related to this hedge.

In December 2020, in connection with the partial repayment of the Term Loan, we paid $10.9 million to terminate $500.0 million of the $850.0 million interest rate swaps and settled the outstanding derivative liability of $10.9 million. The unrealized loss remains in accumulated other comprehensive loss and will amortize into "Interest expense" on the consolidated statements of operations until the original maturity date of the Term Loan. For the year ended December 31, 2020, we amortized $0.4 million into interest expense out of accumulated other comprehensive loss related to the termination of the interest rate swaps. The remaining $350.0 million interest rate swaps were re-designated as a cash flow hedge on LIBOR-based borrowings and continue to be effective.

The components of the loss on designated cash flow hedge related to changes in the fair value of our interest rate swaps were as follows (in millions):

	December 31, 2020	December 31, 2019
Change in fair value of interest rate swaps	$ (5.6)	$ (12.4)
Tax benefit	1.3	3.4
Loss on designated cash flow hedge	$ (4.3)	$ (9.0)

The interest expense, recognized from accumulated other comprehensive loss from the monthly settlement and amortization of the termination payment of our interest rate swaps, included in our consolidated statements of operations were as follows (in millions):

	December 31, 2020	December 31, 2019
Interest expense	$ 14.5	$ 0.4

We expect to recognize an additional $18.2 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, 2020	December 31, 2019
Fair value of derivative liabilities—current	$ (7.6)	$ (5.6)
Fair value of derivative liabilities—long-term	—	(6.8)
Net fair value of interest rate swaps	$ (7.6)	$ (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,		
	2020	2019	2018
Change in fair value of derivatives	$ (10.5)	$ (0.1)	$ 10.1
Realized gain (loss) on derivatives	(11.5)	14.5	(4.9)
Gain (loss) on derivative activity	$ (22.0)	$ 14.4	$ 5.2

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

	December 31, 2020	December 31, 2019
Fair value of derivative assets—current	$ 25.0	$ 12.9
Fair value of derivative assets—long-term	4.9	4.3
Fair value of derivative liabilities—current	(29.5)	(8.8)
Fair value of derivative liabilities—long-term	(2.5)	—
Net fair value of commodity swaps	$ (2.1)	$ 8.4

Set forth below are the summarized notional volumes and fair values of all instruments related to commodity swaps that we held for price risk management purposes and the related physical offsets at December 31, 2020 (in millions). The remaining term of the contracts extend no later than December 2022.

		December 31, 2020		
Commodity	Instruments	Unit	Volume	Net Fair Value
NGL (short contracts)	Swaps	Gallons	(117.3)	$ (14.8)
NGL (long contracts)	Swaps	Gallons	13.7	0.3
Natural gas (short contracts)	Swaps	MMbtu	(15.9)	1.4
Natural gas (long contracts)	Swaps	MMbtu	10.7	1.2
Crude and condensate (short contracts)	Swaps	MMbbls	(10.1)	(7.0)
Crude and condensate (long contracts)	Swaps	MMbbls	2.5	16.8
Total fair value of commodity swaps				$ (2.1)

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 commodity swap contracts, the maximum loss on our gross receivable position of $29.9 million as of December 31, 2020 would be reduced to $9.2 million due to the offsetting of gross fair value payables against gross fair value receivables as allowed by the ISDAs.

(13) Fair Value Measurements

ASC 820, *Fair Value Measurements and Disclosures* ("ASC 820"), sets forth a framework for measuring fair value and required disclosures about fair value measurements of assets and liabilities. Fair value under ASC 820 is defined as the price at which an asset could be exchanged in a current transaction between knowledgeable, willing parties. A liability's fair value is defined as the amount that would be paid to transfer the liability to a new obligor, not the amount that would be paid to settle the liability with the creditor. Where available, fair value is based on observable market prices or parameters or derived from such prices or parameters. Where observable prices or inputs are not available, use of unobservable prices or inputs are used to estimate the current fair value, often using an internal valuation model. These valuation techniques involve some level of management estimation and judgment, the degree of which is dependent on the item being valued.

ASC 820 established a three-tier fair value hierarchy, which prioritizes the inputs used in measuring fair value. These tiers include: Level 1, defined as observable inputs such as quoted prices in active markets; Level 2, defined as inputs other than quoted prices in active markets that are either directly or indirectly observable; and Level 3, defined as unobservable inputs in which little or no market data exists, therefore requiring an entity to develop its own assumptions.

Our derivative contracts primarily consist of commodity swap contracts, which are not traded on a public exchange. The fair values of commodity swap contracts are determined using discounted cash flow techniques. The techniques incorporate Level 1 and Level 2 inputs for future commodity prices that are readily available in public markets or can be derived from information available in publicly-quoted markets. These market inputs are utilized in the discounted cash flow calculation considering the instrument's term, notional amount, discount rate, and credit risk and are classified as Level 2 in hierarchy.

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

	Level 2	
	December 31, 2020	December 31, 2019
Interest rate swaps (1)	$ (7.6)	$ (12.4)
Commodity swaps (2)	$ (2.1)	$ 8.4

(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, 2020		December 31, 2019	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Long-term debt (1)	$ 4,593.8	$ 4,318.2	$ 4,764.3	$ 4,444.2

(1) The carrying value of long-term debt as of December 31, 2020 includes current maturities. The carrying value of the long-term debt is reduced by debt issuance costs of $ 32.6 million and $29.8 million at December 31, 2020 and 2019, respectively. The respective fair values do not factor in debt issuance costs.

The carrying amounts of our cash and cash equivalents, accounts receivable, and accounts payable approximate fair value due to the short-term maturities of these assets and liabilities.

As of December 31, 2020, we had total borrowings under senior unsecured notes of $4.0 billion maturing between 2024 and 2047 with fixed interest rates ranging from 4.15% to 5.625%. As of December 31, 2019, we had total borrowings under senior unsecured notes of $3.6 billion maturing between 2024 and 2047 with fixed interest rates ranging from 4.15% to 5.60%.

The fair values of all senior unsecured notes as of December 31, 2020 and 2019 were based on Level 2 inputs from third-party market quotations.

(14) 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 the 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 the General Partner or interfering with a client or customer of the 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.

(15) Segment Information

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;

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

- *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;

- *North Texas Segment.* The North Texas segment includes our natural gas gathering, processing, and transmission activities in North Texas; 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 evaluate the performance of our operating segments based on segment profit and adjusted gross margin. Adjusted gross 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 additional information. Summarized financial information for our reportable segments is shown in the following tables (in millions):

	Permian	Louisiana	Oklahoma	North Texas	Corporate	Totals
Year Ended December 31, 2020						
Natural gas sales	$ 150.1	$ 330.5	$ 153.1	$ 70.3	$ —	$ 704.0
NGL sales	0.2	1,545.4	2.8	—	—	1,548.4
Crude oil and condensate sales	558.1	126.7	40.3	—	—	725.1
Product sales	708.4	2,002.6	196.2	70.3	—	2,977.5
NGL sales—related parties	312.6	31.4	296.4	115.2	(755.6)	—
Crude oil and condensate sales—related parties	0.6	—	(0.1)	3.6	(4.1)	—
Product sales—related parties	313.2	31.4	296.3	118.8	(759.7)	—
Gathering and transportation	42.8	46.5	228.7	179.2	—	497.2
Processing	24.1	2.0	123.6	132.6	—	282.3
NGL services	—	75.8	—	0.2	—	76.0
Crude services	16.8	45.2	16.5	0.2	—	78.7
Other services	1.2	1.6	0.4	0.9	—	4.1
Midstream services	84.9	171.1	369.2	313.1	—	938.3
Crude services—related parties	—	—	0.3	—	(0.3)	—
Midstream services—related parties	—	—	0.3	—	(0.3)	—
Revenue from contracts with customers	1,106.5	2,205.1	862.0	502.2	(760.0)	3,915.8
Cost of sales, exclusive of operating expenses and depreciation and amortization (1)	(842.2)	(1,787.0)	(365.5)	(153.8)	760.0	(2,388.5)
Loss on derivative activity	—	—	—	—	(22.0)	(22.0)
Adjusted gross margin	264.3	418.1	496.5	348.4	(22.0)	1,505.3
Operating expenses	(94.2)	(120.0)	(82.2)	(77.4)	—	(373.8)
Segment profit (loss)	170.1	298.1	414.3	271.0	(22.0)	1,131.5
Depreciation and amortization	(125.2)	(145.8)	(216.9)	(143.4)	(7.3)	(638.6)
Impairments	(184.6)	(170.0)	(0.7)	—	(7.5)	(362.8)
Gain (loss) on disposition of assets	(11.2)	0.1	0.3	2.0	—	(8.8)
General and administrative	—	—	—	—	(103.3)	(103.3)
Interest expense, net of interest income	—	—	—	—	(223.3)	(223.3)
Gain on extinguishment of debt	—	—	—	—	32.0	32.0
Income from unconsolidated affiliates	—	—	—	—	0.6	0.6
Other income	—	—	—	—	0.3	0.3
Income (loss) before non-controlling interest and income taxes	$ (150.9)	$ (17.6)	$ 197.0	$ 129.6	$ (330.5)	$ (172.4)
Capital expenditures	$ 181.1	$ 44.6	$ 17.9	$ 16.9	$ 2.1	$ 262.6

(1) Includes related party cost of sales of $8.7 million for the year ended December 31, 2020 and excludes all operating expenses as well as depreciation and amortization related to our operating segments of $631.3 million for the year ended December 31, 2020.

	Permian	Louisiana	Oklahoma	North Texas	Corporate	Totals
Year Ended December 31, 2019						
Natural gas sales	$ 94.3	$ 416.6	$ 236.4	$ 129.3	$ —	$ 876.6
NGL sales	0.9	1,725.6	19.6	30.9	—	1,777.0
Crude oil and condensate sales	1,975.0	291.9	109.6	—	—	2,376.5
Product sales	2,070.2	2,434.1	365.6	160.2	—	5,030.1
Natural gas sales—related parties	0.4	—	—	—	(0.4)	—
NGL sales—related parties	347.7	25.7	421.1	94.8	(889.3)	—
Crude oil and condensate sales—related parties	13.5	1.7	—	5.5	(20.7)	—
Product sales—related parties	361.6	27.4	421.1	100.3	(910.4)	—
Gathering and transportation	48.8	58.3	234.5	196.4	—	538.0
Processing	30.5	3.2	138.2	143.0	—	314.9
NGL services	—	50.6	—	0.1	—	50.7
Crude services	19.2	51.9	19.8	—	—	90.9
Other services	12.0	0.7	0.1	1.1	—	13.9
Midstream services	110.5	164.7	392.6	340.6	—	1,008.4
NGL services—related parties	—	(3.4)	—	—	3.4	—
Crude services—related parties	—	—	1.8	—	(1.8)	—
Midstream services—related parties	—	(3.4)	1.8	—	1.6	—
Revenue from contracts with customers	2,542.3	2,622.8	1,181.1	601.1	(908.8)	6,038.5
Cost of sales, exclusive of operating expenses and depreciation and amortization (1)	(2,283.9)	(2,181.6)	(627.0)	(208.8)	908.8	(4,392.5)
Gain on derivative activity	—	—	—	—	14.4	14.4
Adjusted gross margin	258.4	441.2	554.1	392.3	14.4	1,660.4
Operating expenses	(112.9)	(147.3)	(104.0)	(102.9)	—	(467.1)
Segment profit	145.5	293.9	450.1	289.4	14.4	1,193.3
Depreciation and amortization	(119.8)	(154.1)	(194.9)	(139.8)	(8.4)	(617.0)
Impairments	(3.5)	(188.7)	(813.5)	(127.8)	—	(1,133.5)
Gain (loss) on disposition of assets	(0.3)	2.6	0.1	(0.5)	—	1.9
General and administrative	—	—	—	—	(152.6)	(152.6)
Loss on secured term loan receivable	—	—	—	—	(52.9)	(52.9)
Interest expense, net of interest income	—	—	—	—	(216.0)	(216.0)
Loss from unconsolidated affiliates	—	—	—	—	(16.8)	(16.8)
Other income	—	—	—	—	0.9	0.9
Income (loss) before non-controlling interest and income taxes	$ 21.9	$ (46.3)	$ (558.2)	$ 21.3	$ (431.4)	$ (992.7)
Capital expenditures	$ 364.5	$ 99.9	$ 238.1	$ 39.0	$ 6.9	$ 748.4

(1) Includes related party cost of sales of $21.7 million for the year ended December 31, 2019 and excludes all operating expenses as well as depreciation and amortization related to our operating segments of $608.6 million for the year ended December 31, 2019.

	Permian	Louisiana	Oklahoma	North Texas	Corporate	Totals
Year Ended December 31, 2018						
Natural gas sales	$ 152.3	$ 531.1	$ 189.7	$ 140.6	$ —	$ 1,013.7
NGL sales	0.5	2,786.3	25.2	29.0	—	2,841.0
Crude oil and condensate sales	2,344.1	227.1	85.9	0.5	—	2,657.6
Product sales	2,496.9	3,544.5	300.8	170.1	—	6,512.3
Natural gas sales—related parties	(0.3)	0.3	2.5	—	—	2.5
NGL sales—related parties	454.1	47.4	590.8	49.4	(1,104.3)	37.4
Crude oil and condensate sales—related parties	—	0.2	0.3	1.8	(1.2)	1.1
Product sales—related parties	453.8	47.9	593.6	51.2	(1,105.5)	41.0
Gathering and transportation	28.0	68.8	143.2	146.3	—	386.3
Processing	23.8	3.3	128.7	83.9	—	239.7
NGL services	—	59.6	—	—	—	59.6
Crude services	4.2	60.1	2.8	—	—	67.1
Other services	8.7	0.9	0.1	0.9	—	10.6
Midstream services	64.7	192.7	274.8	231.1	—	763.3
Gathering and transportation—related parties	—	—	80.6	122.7	—	203.3
Processing—related parties	—	—	48.5	108.5	—	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	3.3	130.6	231.7	(3.3)	377.2
Revenue from contracts with customers	3,030.3	3,788.4	1,299.8	684.1	(1,108.8)	7,693.8
Cost of sales, exclusive of operating expenses and depreciation and amortization (1)	(2,808.3)	(3,365.7)	(743.6)	(199.2)	1,108.8	(6,008.0)
Gain on derivative activity	—	—	—	—	5.2	5.2
Adjusted gross margin	222.0	422.7	556.2	484.9	5.2	1,691.0
Operating expenses	(96.1)	(154.3)	(90.3)	(112.7)	—	(453.4)
Segment profit	125.9	268.4	465.9	372.2	5.2	1,237.6
Depreciation and amortization	(111.0)	(150.9)	(178.8)	(127.9)	(8.7)	(577.3)
Impairments	(138.5)	(24.6)	—	(202.7)	—	(365.8)
Gain (loss) on disposition of assets	—	(0.1)	(0.8)	0.4	0.1	(0.4)
General and administrative	—	—	—	—	(140.3)	(140.3)
Interest expense, net of interest income	—	—	—	—	(182.3)	(182.3)
Income from unconsolidated affiliates	—	—	—	—	13.3	13.3
Other income	—	—	—	—	0.6	0.6
Income (loss) before non-controlling interest and income taxes	$ (123.6)	$ 92.8	$ 286.3	$ 42.0	$ (312.1)	$ (14.6)
Capital expenditures	$ 271.7	$ 54.4	$ 493.8	$ 24.7	$ 5.3	$ 849.9

(1) Includes related party cost of sales of $114.1 million for the year ended December 31, 2018 and excludes all operating expenses as well as depreciation and amortization related to our operating segments of $568.6 million for the year ended December 31, 2018.

The table below represents information about segment assets as of December 31, 2020 and 2019 (in millions):

Segment Identifiable Assets:	December 31, 2020	December 31, 2019
Permian	$ 2,188.1	$ 2,465.7
Louisiana	2,284.8	2,562.0
Oklahoma	2,816.4	3,035.0
North Texas	1,001.7	1,135.8
Corporate (1)	259.9	137.3
Total identifiable assets	$ 8,550.9	$ 9,335.8

(1) Includes accounts receivable sold to the SPV for collateral under the AR Facility for the year ended December 31, 2020.

(16) Quarterly Financial Data (Unaudited)

Summarized unaudited quarterly financial data is presented below (in millions, except per unit data):

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total
2020					
Revenues	$ 1,156.1	$ 744.9	$ 928.5	$ 1,064.3	$ 3,893.8
Impairments	$ 353.0	$ 1.5	$ —	$ 8.3	$ 362.8
Operating income (loss)	$ (245.5)	$ 70.7	$ 100.5	$ 92.3	$ 18.0
Net income attributable to non-controlling interest	$ 26.4	$ 25.7	$ 26.6	$ 27.2	$ 105.9
Net income (loss) attributable to ENLC	$ (286.8)	$ 4.1	$ 12.6	$ (151.4)	$ (421.5)
Net income (loss) attributable to ENLC per unit:					
Basic common unit	$ (0.59)	$ 0.01	$ 0.03	$ (0.31)	$ (0.86)
Diluted common unit	$ (0.59)	$ 0.01	$ 0.03	$ (0.31)	$ (0.86)
2019					
Revenues	$ 1,779.2	$ 1,710.0	$ 1,408.0	$ 1,155.7	$ 6,052.9
Impairments	$ 186.5	$ —	$ —	$ 947.0	$ 1,133.5
Operating income (loss)	$ (88.7)	$ 53.1	$ 96.5	$ (821.7)	$ (760.8)
Net income attributable to non-controlling interest	$ 41.5	$ 25.2	$ 25.7	$ 27.3	$ 119.7
Net income (loss) attributable to ENLC	$ (176.3)	$ (16.1)	$ 11.8	$ (938.7)	$ (1,119.3)
Net income (loss) attributable to ENLC per unit:					
Basic common unit	$ (0.45)	$ (0.03)	$ 0.02	$ (1.92)	$ (2.41)
Diluted common unit	$ (0.45)	$ (0.03)	$ 0.02	$ (1.92)	$ (2.41)
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)	$ 105.3	$ 148.8	$ 89.8	$ (190.1)	$ 153.8
Net income (loss) attributable to non-controlling interest	$ 44.7	$ 74.2	$ 37.3	$ (175.8)	$ (19.6)
Net income (loss) attributable to ENLC	$ 12.4	$ 28.0	$ 7.7	$ (61.3)	$ (13.2)
Net income (loss) attributable to ENLC per unit:					
Basic common unit	$ 0.07	$ 0.15	$ 0.04	$ (0.34)	$ (0.07)
Diluted common unit	$ 0.07	$ 0.15	$ 0.04	$ (0.34)	$ (0.07)

(17) Supplemental Cash Flow Information

The following schedule summarizes cash paid for interest, cash paid for income taxes, cash paid for finance leases included in cash flows from financing activities, cash paid for operating leases included in cash flows from operating activities, non-cash investing activities, and non-cash financing activities for the periods presented (in millions):

	Year Ended December 31,		
Supplemental disclosures of cash flow information:	**2020**	**2019**	**2018**
Cash paid for interest	$ 207.3	$ 218.9	$ 186.3
Cash paid (refunded) for income taxes	$ (0.7)	$ 4.0	$ 2.2
Cash paid for finance leases included in cash flows from financing activities	$ —	$ 1.2	$ —
Cash paid for operating leases included in cash flows from operating activities	$ 24.6	$ 29.8	$ —
Non-cash investing activities:			
Non-cash accrual of property and equipment	$ (39.6)	$ (6.5)	$ 6.8
Non-cash right-of-use assets obtained in exchange for operating lease liabilities	$ 9.8	$ 104.1	$ —
Discounted secured term loan receivable from contract restructuring	$ —	$ —	$ 47.7
Non-cash financing activities:			
Receivable from sale of VEX	$ 10.0	$ —	$ —
Redemption of non-controlling interest	$ (4.0)	$ —	$ —

(18) 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, 2020**	**December 31, 2019**
Natural gas and NGLs inventory	$ 44.9	$ 43.4
Prepaid expenses and other	13.8	14.4
Other current assets	$ 58.7	$ 57.8

Other current liabilities:	**December 31, 2020**	**December 31, 2019**
Accrued interest	$ 35.7	$ 37.1
Accrued wages and benefits, including taxes	22.5	31.5
Accrued ad valorem taxes	26.5	28.5
Capital expenditure accruals	10.6	42.4
Retainage liability	1.0	8.7
Short-term lease liability	16.3	21.1
Suspense producer payments	10.6	13.8
Operating expense accruals	8.4	10.8
Other	17.5	12.3
Other current liabilities	$ 149.1	$ 206.2

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

Management of the Managing Member 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 us. We carried out an evaluation, under the supervision and with the participation of management, including the Chief Executive Officer and Chief Financial Officer of the Managing Member, 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, 2020), 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. KPMG LLP, the independent registered public accounting firm that audited the Company's consolidated financial statements included in this report, has issued an attestation report on the Company's internal control over financial reporting, a copy of which appears in "Item 8. Financial Statements and Supplementary Data—Management's Report on Internal Control over Financial Reporting."

(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, 2020 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

Disclosure Pursuant to Item 5.02 of Form 8-K – Departure of Directors or Certain Officers; Election of Directors; Appointment of Certain Officers; Compensatory Arrangements of Certain Officers.

On February 16, 2021, the Board approved changes to the Company's form of performance-based restricted incentive unit agreement (the "Performance-Based Award Agreement") for awards of equity-based compensation to certain officers including the principal executive officer, principal financial officer, and other NEOs, under the EnLink Midstream, LLC 2014 Long-Term Incentive Plan.

The principal change to the form of the Performance-Based Award Agreement was to adopt the metric free cash flow after distributions ("FCFAD") as the cash flow performance goal in the Performance-Based Award Agreement rather than the previously used distributable cash flow ("DCF"). FCFAD is now the principal cash flow metric used by the Company in its earnings announcements.

Also on the same date, the Operating Partnership amended and restated existing Performance-Based Award Agreements entered into with each of the NEOs to use FCFAD rather than DCF as the cash flow performance goal.

For more information on the terms of our Performance-Based Award Agreement Agreements and relevant 2021 targets, see "Item 11—Executive Compensation—Compensation Discussion and Analysis—Performance Unit Awards," and the form of Performance-Based Award Agreement, a copy of which is filed with this report as Exhibit 10.17. This description of the form of Performance-Based Award Agreement does not purport to be complete and is qualified in its entirety by reference to the form of Performance-Based Award Agreement, which is incorporated herein by reference.

PART III

Item 10. Directors, Executive Officers, and Corporate Governance

We are managed by the board of directors and executive officers of the Managing Member. The Managing Member is not elected by our unitholders and will not be subject to re-election by our unitholders in the future. The Managing Member has a board of directors, and our common unitholders are not entitled to elect the directors or to participate directly or indirectly in our management or operations. Our operational personnel are employees of the Operating Partnership. References to our officers, directors, and employees are references to the officers, directors, and employees of the Managing Member or the Operating Partnership.

The following table shows information for the members of the Board of Directors of the Managing Member (the "Board") and the executive officers of the Managing Member. Executive officers and directors serve until their successors are duly appointed or elected.

Name	Age	Position with EnLink Midstream Manager, LLC
Barry E. Davis	59	Chairman and Chief Executive Officer
Benjamin D. Lamb	41	Executive Vice President and Chief Operating Officer
Pablo G. Mercado	44	Executive Vice President and Chief Financial Officer
Alaina K. Brooks	46	Executive Vice President, Chief Legal and Administrative Officer, and Secretary
Deborah G. Adams (1)	60	Director and Member of the Audit Committee
William J. Brilliant	45	Director and Member of the Governance and Compensation Committee
James C. Crain (1)	72	Director and Member of the Audit and Conflicts (2) Committees
Leldon E. Echols (1)	65	Director and Member of the Governance and Compensation and Audit (2) Committees
Thomas W. Horton	59	Director
James K. Lee	39	Director
Richard P. Schifter	67	Director
Scott E. Telesz	53	Director
Kyle D. Vann (1)	73	Director and Member of the Conflicts and Governance and Compensation (2) Committees

(1) Independent director.
(2) Chairperson of committee.

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 held management roles in the energy industry since 1984. Mr. Davis led our predecessor, Crosstex Energy, from its founding in 1996 through its merger with Devon to create ENLC. During this time, Crosstex Energy completed the initial public offerings of Crosstex Energy, L.P. in 2002 and Crosstex Energy, Inc. in 2004. Crosstex Energy was formed in 1996 when Mr. Davis led the management buyout of the midstream assets of Comstock Natural Gas, Inc., a subsidiary of Comstock Resources, Inc. Prior to the formation of Crosstex Energy, 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. 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 is a member and former president of the Natural Gas and Electric Power Society, Dallas Wildcat Committee, and the Dallas Petroleum Club, as well as a member of the World Presidents Organization and the National Petroleum Council. 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.

Benjamin D. Lamb, Executive Vice President and Chief Operating Officer, has served in this position since June 2018. Mr. Lamb previously 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.

Pablo G. Mercado, Executive Vice President and Chief Financial Officer, has served in this position since July 2020. Prior to July 2020, Mr. Mercado served as Senior Vice President and Chief Financial Officer of Forum Energy Technologies, Inc. ("Forum Energy") from March 2018 to July 2020. Mr. Mercado also previously held various finance and corporate development positions at Forum Energy since joining in November 2011, including Senior Vice President, Finance from June 2017 to March 2018 and Vice President, Operations Finance from August 2015 to June 2017. Prior to Forum Energy, Mr. Mercado was as an investment banker with the Oil and Gas Group of Credit Suisse from 2005 to October 2011. Between 1998 and 2005, Mr. Mercado was an investment banker at UBS Investment Bank and Bank of America Merrill Lynch, working primarily with companies in the oil and gas industry. Mr. Mercado holds a Bachelor of Business Administration and a Bachelor of Arts in Economics from Southern Methodist University and a Master of Business Administration from The University of Chicago Booth School of Business. He currently serves on the Board of Directors as a member of the Audit and Governance Committees of Comfort Systems USA, Inc. and on the Board of Directors of the Energy Infrastructure Council, a non-profit trade association for companies that develop and operate energy infrastructure.

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 of the General Partner in January 2019. Ms. Brooks previously served in a number of our 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, 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.

Deborah G. Adams has served as a director of the Managing Member since February 2020. Ms. Adams served on the Executive Leadership Team at Phillips 66 as Senior Vice President of Health, Safety, and Environment, Projects and Procurement from 2014 until her retirement in October 2016. Ms. Adams previously served as Division President, Transportation for Phillips 66 and ConocoPhilipps from 2008 to 2014. Prior to this time, Ms. Adams held various leadership positions at ConocoPhillips, including Chief Procurement Officer, General Manager, International Refining, and Manager, Global Downstream Information Systems. She has also served on several of ConocoPhillips' joint venture boards. Ms. Adams currently serves as a director on the board of directors of Gulfport Energy, MRC Global, Inc., and Austin Industries, an employee-owned construction company. Ms. Adams has also served as a member of the Oklahoma State University Foundation Board of Trustees and on the University's Board of Governors. In 2014, she was inducted into the Oklahoma State University College of Engineering, Architecture and Technology Hall of Fame, and in 2015, the National Diversity Council named Adams to the list of the Top 50 Most Powerful Women in Oil and Gas. Ms. Adams received a Bachelor of Science in chemical engineering from Oklahoma State University. Ms. Adams was selected to serve as a director due to, among other factors, her extensive experience in the energy sector, including midstream, her leadership skills and her business experience, including her expertise in a wide range of operational areas.

William J. Brilliant has served as a director of the Managing Member since July 2018. Mr. Brilliant served as a director of the General Partner from July 2018 until January 2019. Mr. Brilliant is a Partner and leader of GIP's energy investment business. Mr. Brilliant is a member of GIP's Investment and Operating Committees and has been a member of GIP's investment team since 2007. Prior to joining GIP, he was an investment banker at Lehman Brothers. Mr. Brilliant currently serves on the Boards of Directors of Hess Midstream Partners GP LLC and Hess Infrastructure Partners. He previously served as a director of the general partner of Access Midstream Partners L.P. from June 2012 through July 2014. Mr. Brilliant holds a B.A. from the University of California at Los Angeles and an M.B.A. from the Wharton School of the University of Pennsylvania. Mr. Brilliant was selected to serve as a director due to, among other factors, his energy industry background, particularly his expertise in mergers and acquisitions.

James C. Crain has served as a director of the Managing Member since March 2014. Mr. Crain joined Crosstex Energy, Inc., the predecessor to ENLC, as a director in July 2006. Mr. Crain served as a director of the General Partner from December 2005 to August 2008. Mr. Crain retired as president of Marsh Operating Company in July 2013, where he worked since 1984 and currently serves as an advisor to Marsh Operating Company and is a private investor. In addition, Mr. Crain serves as a consultant for Yorktown Partners, LLC, an energy oriented private equity fund, where he advises certain portfolio companies in connection with their business activities. Prior to Marsh, he was a partner at the law firm of Jenkens & Gilchrist. Mr. Crain previously served on the board of Approach Resources, Inc. He graduated from the University of Texas at Austin with a B.B.A.

degree, a Master of Professional Accountancy, and a Doctor of Jurisprudence. Mr. Crain was selected to serve as a director due to his legal background and his experience in the oil and natural gas industry, among other factors.

Leldon E. Echols has served as a director of the Managing Member since March 2014. Mr. Echols joined Crosstex Energy, Inc, the predecessor to ENLC, as a director in January 2008. Mr. Echols served as a director of the General Partner from March 2014 until January 2019. Mr. Echols is a private investor. Mr. Echols also currently serves as an independent director of Trinity Industries, Inc. and HollyFrontier Corporation. Mr. Echols brings over 30 years of financial and business experience to the Board. After 22 years with the accounting firm Arthur Andersen LLP, which included serving as managing partner of the firm's audit and business advisory practice in North Texas, Colorado, and Oklahoma, Mr. Echols spent six years with Centex Corporation as executive vice president and chief financial officer. He retired from Centex Corporation in June 2006. Mr. Echols previously served as a member of the board of directors of Roofing Supply Group Holdings, Inc., a private company. He also served on the board of TXU Corporation where he chaired the Audit Committee and was a member of the Strategic Transactions Committee until the completion of the private equity buyout of TXU in October 2007. Mr. Echols earned a Bachelor of Science in accounting from Arkansas State University. He is a member of the American Institute of Certified Public Accountants and the Texas Society of CPAs. Mr. Echols was selected to serve as a director due to his accounting and financial experience and service as the chief financial officer for another public company, among other factors.

Thomas W. Horton has served as a director of the Managing Member since August 2019. Mr. Horton is a Partner at GIP. Prior to joining GIP, Mr. Horton was a senior advisor at Warburg Pincus, LLC, a private equity firm from 2015 to 2019. He was the chairman of American Airlines Group Inc. from 2013 to 2014 and chairman, president, and chief executive officer of American Airlines Inc. and AMR Corp. from 2011 to 2013 after being named president of American Airlines in 2010. Previously, he served as executive vice president and chief financial officer of AMR and American Airlines from 2006 to 2010 and vice chairman and chief financial officer of AT&T Corp. from 2002 to 2006. Mr. Horton currently serves as a director of General Electric Co. and Walmart Inc. He also serves on the executive board of the Cox School of Business at Southern Methodist University. Mr. Horton was selected to serve as a director due to, among other factors, his extensive executive and financial experience, business expertise, and leadership skills.

James K. Lee has served as a director of the Managing Member since February 2020. Mr. Lee is an Investment Principal at GIP and a key member of GIP's North American energy investment business. Mr. Lee has been a member of GIP's investment team since 2009.Prior to joining GIP, Mr. Lee was an investment banker at Goldman Sachs & Co. Mr. Lee previously served on the Board of Directors of Competitive Power Ventures, a privately held electric power generation development and asset management company. Mr. Lee holds a Bachelor of Commerce (Honors and University Medal) and a Bachelor of Laws from the University of New South Wales. Mr. Lee was selected to serve as a director due to, among other factors, his energy industry background and his banking and financial experience.

Richard P. Schifter has served as a director of the Managing Member since December 2020. Mr. Schifter is a senior advisor of TPG, a leading global private investment firm. He was a partner at TPG from 1994 through 2013. Prior to joining TPG, he was a partner at the law firm of Arnold & Porter in Washington, D.C. He joined Arnold & Porter in 1979 and was a partner from 1986 through 1994. Mr. Schifter currently serves on the board of directors of LPL Financial Holdings Inc., Avianca Holdings, S.A. and ProSight Global, Inc. Schifter is also a member of the board of overseers of the University of Pennsylvania Law School. He received a Bachelor of Arts with distinction from George Washington University and a Juris Doctor cum laude from the University of Pennsylvania Law School. Mr. Schifter brings to the Board extensive legal and investment expertise.

Scott E. Telesz has served as a director of the Managing Member since December 2020. Mr. Telesz is an Operating Partner of GIPand has over 25 years of experience in the manufacturing industry. Prior to joining GIP in August 2018, hespent 8 years as an executive at Praxair, an industrial gas manufacturing company, most recently as executive vice president in charge of Praxair's U.S. atmospheric gases businesses, Praxair Canada and Praxair Surface Technologies from 2014 until May 2018. Before joining Praxair, Mr. Telesz spent 12 years at GE/SABIC where he ran various electrical products and plastics businesses. He currently serves on the board of directors of Hess Midstream GP LLC and of Edinburgh Airport. Mr. Telesz also serves on the Board of Visitors of Duke University's Pratt School of Engineering. He earned a Bachelor of Science in electrical engineering from Duke University in 1989 and a Master of Business Administration from Harvard Business School in 1994. Mr. Telesz was selected to serve as a director due to, among other factors, his extensive executive and business expertise, his engineering background, and his leadership skills.

Kyle D. Vann has served as a director of the Managing Member since January 2019 and served as a director of the General Partner from April 2016 until January 2019. Mr. Vann began his career with Exxon Corporation in 1969. After ten years at Exxon, he joined Koch Industries and served in various leadership capacities, including senior vice president from 1995-2000. In 2001, he then took on the role of CEO of Entergy-Koch, LP, an energy trading and transportation company, which was sold in 2004. Mr. Vann consulted with Entergy until 2020 and was an executive advisor to CCMP Capital Advisors, LLC from

2012-2017. He also serves on the board of PQ Chemical and is on the advisory boards of Texon, L.P. and Refined Technologies, Inc. He also serves as a director on the Boards of Mars Hill Productions and Generous Giving, which are private, charitable non-profits. Mr. Vann graduated from the University of Kansas with a Bachelor of Science in chemical engineering. He is a member of the Board of Advisors for the University of Kansas School of Engineering (where he was a recipient of the Distinguished Engineering Service Award). Mr. Vann was selected to serve as a director due to his extensive experience in the energy industry and his business expertise, among other factors.

Independent Directors

Because we are a “controlled company” within the meaning of the NYSE rules, the NYSE does not require the Board to be composed of a majority of directors who meet the criteria for independence required by the NYSE or to maintain nominating/corporate governance and compensation committees composed entirely of independent directors. Our Board has adopted Governance Guidelines that require at least three members of our Board to be independent directors as defined by the rules of the NYSE.

For a director to be “independent” under the NYSE standards, the Board must affirmatively determine that the director has no material relationship with the Company (either directly or as a partner, shareholder or officer of any organization that has a relationship with the Company, other than in his or her capacity as a director of the Company). In addition, the director must meet certain independence standards specified by the NYSE, including a requirement that the director was not employed by the Managing Member or engaged in certain business dealings with the Managing Member. Using these standards for determining independence, the Board has determined that Messrs. Vann, Crain, and Echols and Ms. Adams qualify as “independent” directors.

In addition, the members of the Audit Committee of our Board each qualify as “independent” under special standards established by the Commission for members of audit committees, and the Audit Committee includes at least one member who is determined by our Board to meet the qualifications of an “audit committee financial expert” in accordance with Commission rules, including that the person meets the relevant definition of an “independent” director. Mr. Echols is an independent director who has been determined 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 the individual with respect to certain accounting and auditing matters. The designation does not impose on such director any duties, obligations, or liabilities that are greater than are generally imposed on the director as a member of the Audit Committee and the Board, and the designation of a director as an audit committee financial expert pursuant to this Commission requirement does not affect the duties, obligations, or liabilities of any other member of the Audit Committee or the Board.

Board Committees

The Board has three standing committees: the Audit Committee, the Conflicts Committee, and the Governance and Compensation Committee. Each member of the Audit Committee is an independent director in accordance with the NYSE standards described above. Each of the Board committees has a written charter approved by the Board. Copies of the charters and our Code of Business Conduct and Ethics are available to any person, free of charge, at our website: www.enlink.com.

The Audit Committee, comprised of Messrs. Echols (chair) and Crain and Ms. Adams, assists the Board in its general oversight of our financial reporting, internal controls, and audit functions, and is directly responsible for the appointment, retention, compensation, and oversight of the work of our independent auditors.

The Conflicts Committee, comprised of Messrs. Crain (chair) and Vann, reviews specific matters that the Board believes may involve conflicts of interest. The Conflicts Committee determines if the resolution of a conflict of interest is fair and reasonable to us. The members of the Conflicts Committee are not directors, officers, or employees of the General Partner. Any matters approved by the Conflicts Committee will be conclusively deemed to be fair and reasonable to us, approved by all of our unitholders, and not a breach by our Managing Member of any duties owed to us or our unitholders.

The Governance and Compensation Committee, comprised of Messrs. Vann (chair), Echols, and Brilliant, reviews matters involving governance, including assessing the effectiveness of current policies, monitoring industry developments, and overseeing certain compensation decisions as well as the compensation plans described herein.

Executive Sessions

The non-management directors meet in executive session without management participation at least quarterly. The non-management directors present at such executive sessions designate a director to preside at such meetings (the "Presiding Non-Management Director"). Unitholders or interested parties may communicate with non-management directors by sending written communications to the following address to the attention of the Presiding Non-Management Director: EnLink Midstream Manager, LLC, 1722 Routh St., Suite 1300, Dallas, Texas 75201.

Code of Ethics and Governance Guidelines

We adopted a Code of Business Conduct and Ethics (the "Code of Ethics") applicable to all of our employees, officers, and directors with regard to company-related activities. The Code of Ethics incorporates guidelines designed to deter wrongdoing and to promote honest and ethical conduct and compliance with applicable laws and regulations. It also incorporates expectations of our employees that enable us to provide accurate and timely disclosure in our filings with the Commission and other public communications. We also adopted Governance Guidelines (the "Governance Guidelines") that outline the important policies and practices regarding our governance and provide an effective framework for the functioning of our Board. A copy of the Code of Ethics and the Governance Guidelines are available to any person, free of charge, within the "Governance Documents" subsection of the "Corporate Governance" section of the investors section of our website at www.enlink.com. If any substantive amendments are made to the Code of Ethics or if we grant any waiver, including any implicit waiver, from a provision of the Code of Ethics to any of our 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

Section 16(a) of the Securities Exchange Act of 1934 requires 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 2020, 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 Susan J. McAden, which Form 4 filing reported one transaction and was due on March 20, 2020 but was filed one day late, (ii) one Form 4 filing for WSIP Egypt Holdings, LP, a beneficial owner of Enfield, which Form 4 filing reported one transaction and was due on November 17, 2020 but was filed two days late, and (iii) one Form 4 filing for The Goldman Sachs Group, Inc., a beneficial owner of Enfield, which Form 4 filing reported one transaction and was due on November 17, 2020 but was filed two days late.

Item 11. Executive Compensation

Governance and Compensation Committee Report

Kyle D. Vann and Leldon E. Echols, who serve on the Governance and Compensation Committee of our Managing Member (the "Committee"), are independent directors in accordance with NYSE standards. The Committee has reviewed and discussed with management the following section titled "Compensation Discussion and Analysis." Based upon its review and discussions, the 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 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 with respect 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. The Managing Member 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 the Managing Member is determined by the Board upon the recommendation of the Committee. Our named executive officers also serve as named executive officers of EnLink Midstream GP, LLC, the General Partner. Therefore, the compensation of the named executive officers discussed below reflects total compensation for services with respect to us and all our 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 Committee's responsibility to design and administer compensation programs that achieve these goals, and to make recommendations to the Board to approve and adopt these programs. The 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 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 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, the specific challenges that we may face, and individual and group contributions made by our executives to us and the Managing Member. The Committee recommended to the Board adjustments to the compensation program and to each individual element as determined necessary to achieve our goals. The Committee retains a compensation consultant to assist in its review and to provide input regarding the compensation program and each individual element.

Role of Compensation Consultant

The Committee retained Mercer (US) Inc., ("Mercer") as its independent compensation consultant to advise the Committee on certain matters relating to compensation programs applicable to the named executive officers and other employees of the General Partner during 2020. In particular, Mercer assisted in the Committee's overall decision-making process 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 Committee about emerging best practices and changes in the regulatory and governance environment. Mercer's work for the Committee did not raise any conflicts of interest in 2020.

Role of Peer Group and Benchmarking

The Committee and Mercer collaborated to identify the following companies as our peer companies in 2020: Crestwood Equity Partners, L.P., DCP Midstream, L.P., Enable Midstream Partners, LP, Equitrans Midstream Corporation, Genesis Energy, L.P., Magellan Midstream Partners, L.P., MPLX, L.P., NuStar Energy L.P., ONEOK Inc., and Targa Resources Corp. (the "Peer Group"). The Committee believes 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 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 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 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 Committee relating to all aspects of executive compensation.

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

Elements of Compensation

For fiscal year 2020, 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 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 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 2020 (and payable for fiscal 2021) are as follows:

	Prior Salary	Base Salary Effective For 2021	Percent Increase (Decrease)
Barry E. Davis	$ 735,000	$ 750,000	2.0 %
Benjamin D. Lamb	$ 491,625	$ 507,000	3.1 %
Pablo G. Mercado	$ 450,000	$ 465,000	3.3 %
Alaina K. Brooks	$ 439,875	$ 465,000	5.7 %
Eric D. Batchelder (1)	$ 450,225	$ —	(100.0)%

(1) In July 2020, Mr. Batchelder departed from his position as Executive Vice President and Chief Financial Officer.

Bonus Awards. The Board and the 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 Board and the 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. For 2020, the STI program included the following Primary Bonus Components:

- *Financial.* Adjusted EBITDA and distributable cash flow (“DCF”) per unit to maximize financial performance.
- *Capital Projects.* Timely and cost-effective capital projects.
- *Operational*. Efficient use of systems, assets, and equipment for meeting contractual obligations, driving customer service, and maximizing cash flow.
- *Environmental and Safety*. Prevention of safety incidents and improvement in safety compliance, operations, and training.

As reflected in the table below, a separate weighting and associated threshold/target/maximum is applied for each of the Primary Bonus Components. The weighting for each 2020 Primary Bonus Component and associated information are as follows:

Component	Weighting	Threshold Level	Target Level	Maximum Level
Financial - Adjusted EBITDA	60%	$996 million	$1,100 million	$1,197 million
Finance - DCF per unit	10%	$1.345	$1.494	$1.643
Capital Projects	10%		Timely and cost-effective capital projects	
Operational	10%		Operational Scorecard	
Environmental and Safety	10%		Environmental and Safety Scorecard	
Total Weighting	**100%**			

Each year, performance under the Primary Bonus Components will be measured, as applicable, on an interpolated “threshold/target/maximum” basis. Actual performance below threshold results in 0% of target, performance at threshold results in 50% of target, and results at the maximum threshold or higher are capped at 200% of target achievement for that component. 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 Board and the 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 Committee and the 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 Board, based on recommendations of the 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 Committee and the Board for the named executive officers will be established by multiplying (i) the relevant named executive officer's target bonus percentage by (ii) the relevant named executive officer's base salary earnings for the applicable year (subject to certain adjustments to account for, among other things, mid-year changes in base salary or a mid-year hiring or termination) by (iii) an achievement percentage for the relevant year.

The Committee believes that a portion of executive compensation for named executive officers must remain discretionary. Therefore, the STI Program contemplates that the Committee and the Board retain discretion with respect to target bonus awards and the final bonus amounts for named executive officers. In this regard, the Committee may exercise such discretion to recommend to the 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 Board based upon the Committee's recommendation and assessment of whether such officer met his or her personal 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 Committee as a whole. All named executive officers met or exceeded their minimum personal performance objectives for 2020. Accordingly, the Committee and the Board awarded bonuses to the named executive officers as follows:

	Target Bonus Percentage (as a % of Base Salary)	2020 Bonus (as a % of Base Salary)	2020 Bonus Amount ($)
Barry E. Davis	125 %	133.8 %	$ 983,658
Benjamin D. Lamb	100 %	109.0 %	$ 536,056
Pablo G. Mercado	90 %	90.8 %	$ 408,757 (1)
Alaina K. Brooks	90 %	98.1 %	$ 431,666
Eric D. Batchelder (2)	90 %	61.1 %	$ 274,980

(1) Includes a $100,000 grant of equity in the form of restricted incentive units that vest on January 1, 2022.
(2) In July 2020, Mr. Batchelder departed from his position as Executive Vice President and Chief Financial Officer.

Long-Term Incentive Plans. 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"). Prior to the Merger, our named executive officers and outside directors were also eligible to receive awards under the EnLink Midstream GP, LLC Long-Term Incentive Plan (the "GP Plan"). The Board, upon the recommendation of the Committee, approves the grants of equity awards to our named executive officers. The 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 performance on a group and individual basis, company performance, market conditions, succession planning, retention, and other factors as determined by the Committee and/or the Board. A brief discussion of each plan follows:

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 Committee determines which eligible individuals receive awards under the 2014 Plan, subject to the Board's approval of awards to our named executive officers. The 2014 Plan is administered by the 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. In subsequent years, the 2014 Plan was amended and restated, resulting in an increase to the number of common units reserved for issuance thereunder. Most recently, the 2014 Plan was amended and restated, effective as of December 28, 2020, to increase the number of common units reserved for issuance to 41,116,046, of which 26,655,865 common units remain eligible for future grants after 2021 awards were made on January 1, 2021. 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. 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.

In general, the 2014 Plan is administered by the Committee. With respect to application of the 2014 Plan to non-employee directors, the 2014 Plan is administered by the Board. The Committee generally has the sole discretion to determine which eligible individuals receive awards under the 2014 Plan, subject to the review of the Board of awards to certain of our executive officers, and the Board has such discretion with respect to which eligible non-employee directors receive awards under 2014 Plan. The 2014 Plan, as currently amended and restated, will automatically expire on September 17, 2030. The 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 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 Board or the 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.

EnLink Midstream GP, LLC Long-Term Incentive Plan. The General Partner adopted the GP Plan for employees, consultants, and independent contractors of the General Partner and its affiliates and outside directors of our Board who perform services for us. 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 was converted into an award with respect to our 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) we assumed all obligations in respect of the GP Plan, and (ii) the Committee (and the Board when applicable) became responsible for the administration of the GP Plan. No future awards will be granted under the GP Plan.

For more information on the 2014 Plan and the GP Plan, see our Information Statement on Schedule 14C filed with the Commission on December 8, 2020 and ENLK's Annual Report on Form 10-K for the year ended December 31, 2018, filed with the Commission on February 20, 2019.

Performance Unit Awards. The Managing Member and the General Partner have granted performance awards under the 2014 Plan and the GP Plan, respectively. Prior to 2019, the performance award agreements provided 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 "Designated Peer Companies") over the applicable performance period. The performance award agreements contemplate that the Designated Peer Companies for an individual performance award (the "Subject Award") are the companies comprising the 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 ENLC's TSR achievement (and with respect to performance units granted prior to the Merger, ENLC's and ENLK's average TSR achievement for periods prior to the Merger and ENLC's TSR for periods thereafter) ("EnLink TSR") for the applicable performance period relative to the TSR achievement of the Designated 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 Designated 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 Designated Peer Companies in respect of periods after the effective time of the Merger.

In 2019, the 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 incentive 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").

Approximately one-fourth of the Total TSR Units (the "Tranche TSR Units") relates to the Cumulative Performance Period and each of the first three performance periods described below. The following table sets out the levels at which the Tranche TSR Units may vest (using linear interpolation) based on the TSR percentile ranking for the applicable performance period relative to the TSR achievement of the Designated Peer Companies:

Performance Level	Achieved 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 below (i.e., the Cash Flow performance goal does not relate to the Cumulative Performance Period). The 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 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 were eligible to vest (using linear interpolation) based on the Cash Flow performance of ENLC for the performance period ending December 31, 2020:

Performance Level	ENLC's Achieved Cash Flow	Vesting percentage of the Tranche CF Units
Below Threshold	Less than $1.345	0%
Threshold	Equal to $1.345	50%
Target	Equal to $1.494	100%
Maximum	Greater than or Equal to $1.643	200%

The following table sets out the levels at which the Tranche CF Units were 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%

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 and Anti-Pledging 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 2020, 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

All of our named executive officers and certain members of senior management have entered into change in control agreements (the "Change in Control Agreements") with the Operating Partnership and severance agreements (the "Severance Agreements" and collectively with the Change in Control Agreements, the "Agreements") with the Operating Partnership. Additionally, as certain individuals become members of senior management, the individual may become a party to a change in control agreement and/or a severance agreement in substantially the same form as the applicable Agreement.

On November 3, 2020, the Operating Partnership amended and restated the existing Change in Control Agreement with each of our named executive officers, other than the Chairman and Chief Executive Officer, to increase the change in control benefit multiplier from two times the change in control benefit to two and a half times the change in control benefit. The change in control benefit multiplier in the Change in Control Agreement with the Company's Chairman and Chief Executive Officer remains unchanged at three times the change in control benefit.

The Agreements restrict the officers from competing with us, the Managing Member, the Operating Partnership, ENLK, the 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, the other named executive officers would be entitled to two and a half times the Severance Benefit, and other members of senior management would be entitled to one and a half times the Severance Benefit.

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 Committee.

Upon a change of control, and except as provided in the award agreement, the 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 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, 2020 are set forth in the table in the section below entitled "Payments Upon Termination or Change of Control."

Role of Executive Officers in Executive Compensation

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

Summary Compensation Table

The following table sets forth certain compensation information for our named executive officers.

Name and Principal Position	Year	Salary ($)(1)	Bonus ($)(2)	Restricted Incentive Unit and Performance Unit Awards ($)(3)	All Other Compensation ($)	Total ($)
Barry E. Davis	2020	763,269	983,658	5,412,084	660,582 (6)	7,819,593
Chairman and Chief Executive Officer	2019	556,000	636,568	4,553,287	744,456	6,490,311
	2018	529,000	784,367	3,835,864	784,034	5,933,265
Benjamin D. Lamb	2020	519,988	536,056	2,706,036	209,641 (7)	3,971,721
Executive Vice President and Chief Operating Officer	2019	491,200	521,207	1,264,284	362,424	2,639,115
	2018	447,500	665,733	4,272,801	703,111	6,089,145
Pablo G. Mercado (4)	2020	225,000	408,757	986,400	223,126 (8)	1,843,283
Executive Vice President and Chief Financial Officer						
Alaina K. Brooks	2020	465,252	431,666	1,391,674	181,311 (9)	2,469,903
Executive Vice President, Chief Legal and Administrative Officer, and Secretary	2019	439,500	444,709	902,261	302,253	2,088,723
	2018	393,300	468,087	2,410,163	204,661	3,476,211
Eric D. Batchelder (5)	2020	296,376	274,980	1,391,674	1,828,577 (10)	3,791,607
Former Executive Vice President and Chief Financial Officer	2019	449,900	429,585	948,218	205,157	2,032,860
	2018	399,200	560,771	3,133,675	304,836	4,398,482

(1) Salary for the year 2020 included regular earnings, an additional 27th pay period, and a one-time paid time off (“PTO”) payout.
(2) Bonuses include all annual bonus payments. For 2020, the named executive officers received bonuses in the form of 100% cash except for Mr. Mercado, who received $100,000 of his 2020 bonus in restricted incentive units that vest on January 1, 2022. 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. Equity awards for 2019 and 2018 represent the grant date fair value of awards computed in accordance with ASC 718.
(3) The amounts shown represent the grant date fair value of awards computed in accordance with ASC 718. See “Item 8. Financial Statements and Supplementary Data—Note 11” for the assumptions made in our valuation of such awards.
(4) Mr. Mercado was appointed as Executive Vice President and Chief Financial Officer on July 13, 2020.
(5) In July 2020, Mr. Batchelder departed from his position as Executive Vice President and Chief Financial Officer.
(6) Amount of all other compensation for Mr. Davis includes a matching 401(k) contribution of $17,100 and DERs with respect to restricted incentive units of ENLC in the amount of $643,842.
(7) Amount of all other compensation for Mr. Lamb includes a matching 401(k) contribution of $17,100 and DERs with respect to restricted incentive units of ENLC in the amount of $192,541.
(8) Amount of all other compensation for Mr. Mercado includes DERs with respect to restricted incentive units of ENLC in the amount of $37,500 and $185,626 toward moving expenses.
(9) Amount of all other compensation for Ms. Brooks includes a matching 401(k) contribution of $17,100 and DERs with respect to restricted incentive units of ENLC in the amount of $164,211.
(10) Amount of all other compensation for Mr. Batchelder includes a matching 401(k) contribution of $17,100 and DERs with respect to restricted incentive units of ENLC in the amount of $77,818. Mr. Batchelder received $1,733,659 in connection with his departure.

CEO Pay Ratio

For fiscal year 2020, the annual total compensation for Mr. Davis was $7.8 million and for the median employee was $105,806. The resulting ratio of annual total compensation of Mr. Davis to the annual total compensation of our median employee was 74:1. 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 2020 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, 2020, the last business day of the 2020 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 2020. 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 2020 Summary Compensation Table above.

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 2020 Table

The following table provides information concerning each grant of an award made to a named executive officer for fiscal year 2020, 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	1/1/2020	—	—	—	391,499	(2)	2,399,889
	1/1/2020	195,750	391,499	782,998	—	(3)	3,012,195
Benjamin D. Lamb	1/1/2020	—	—	—	195,749	(2)	1,199,941
	1/1/2020	97,875	195,749	391,498	—	(3)	1,506,094
Pablo G. Mercado (4)	7/13/2020	—	—	—	200,000	(5)	468,000
	7/13/2020	100,000	200,000	400,000	—	(6)	518,400
Alaina K. Brooks	1/1/2020	—	—	—	100,671	(2)	617,113
	1/1/2020	50,336	100,671	201,342	—	(3)	774,561
Eric D. Batchelder (7)	1/1/2020	—	—	—	100,671	(2)	617,113
	1/1/2020	50,336	100,671	201,342	—	(3)	774,561

(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—Note 11" for the assumptions made in our valuation of such awards.
(2) These grants include DERs that provide for distribution on restricted incentive units if made on unrestricted common units during the restriction period unless otherwise forfeited and vest 100% on January 1, 2023.
(3) 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, 2023, recipients receive DERs, if any, with respect to the number of performance awards vested.
(4) In July 2020, Mr. Mercado was appointed Executive Vice President and Chief Financial Officer and was awarded restricted incentive units at the time of his appointment.
(5) 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 July 13, 2023.
(6) In July 2020, Mr. Mercado was appointed Executive Vice President and Chief Financial Officer and was awarded performance units at the time of his appointment. 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 July 13, 2023, recipients receive DERs, if any, with respect to the number of performance awards vested.
(7) In July 2020, Mr. Batchelder departed from his position as Executive Vice President and Chief Financial Officer.

Outstanding Equity Awards at Fiscal Year-End Table for Fiscal Year 2020

The following table provides information concerning all outstanding equity awards made to a named executive officer as of December 31, 2020, 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 ($)(2)	Equity Incentive Plan Awards: Number of Unearned Units or Other Rights that Have Not Vested (#)(3)(4)(5)(6)	Equity Incentive Plan Awards: Market or Payout Value of Unearned Units or Other Rights That Have Not Vested ($)(2)
Barry E. Davis	2023	391,499	1,452,461	391,499	1,452,461
	2022	135,318	502,030	391,292 (7)	1,451,693
	2021	98,730	366,288	98,730	366,288
Benjamin D. Lamb	2023	195,749	726,229	195,749	726,229
	2022	—	—	96,525	358,108
	2021	139,925	519,122	—	—
Pablo Mercado	2023	200,000	742,000	200,000	742,000
Alaina K. Brooks	2023	100,671	373,489	100,671	373,489
	2022	—	—	72,394	268,582
	2021	73,780	273,724	26,000	96,460
Eric D. Batchelder (8)	2023	—	—	17,544	65,088
	2022	—	—	26,956	100,007

(1) Restricted incentive units vesting in 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. Restricted incentive units vesting in 2023 vest on January 1st and July 13th, as applicable.
(2) The closing price for the ENLC common units was $3.71 as of December 31, 2020.
(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 are contingent upon (i) the ENLC and ENLK 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 and 2023 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 2023 are contingent upon (i) the EnLink TSR performance measured against a peer group of companies and (ii) EnLink's achieved free cash flow after distributions per unit outstanding.
(7) Vesting of awards in August 2022 for Mr. Davis are contingent upon the EnLink TSR performance measured against a peer group of companies.
(8) In July 2020, Mr. Batchelder departed from his position as Executive Vice President and Chief Financial Officer. Pursuant to the terms of his award agreements and change in control agreement, Mr. Batchelder's outstanding restricted incentive units vested at 100% and a portion of his outstanding performance units vested at 16.8% of target in July 2020. The remaining outstanding performance units not vested in 2020 will vest on the original vesting date of January 1, 2022 and January 1, 2023, as applicable, depending on whether and to what extent the performance metrics thereunder are satisfied.

Units Vested Table for Fiscal Year 2020

The following table provides information related to the vesting of restricted units and restricted incentive units during fiscal year ended 2020.

ENLINK MIDSTREAM, LLC—UNITS VESTED

Name	Date Vested	Number of Units Acquired on Vesting	Value Per Unit Realized on Vesting ($)	Total ($)
Barry E. Davis	1/1/2020	106,667	6.13	653,869
	1/15/2020	106,667	5.74	612,269
	2/21/2020	91,139	4.54	413,771
Benjamin D. Lamb	1/1/2020	65,515	6.13	401,607
	2/21/2020	74,622	4.54	338,784
	8/1/2020	93,849	2.45	229,930
Pablo G. Mercado	—	—	—	—
Alaina K. Brooks	1/1/2020	19,649	6.13	120,448
	1/15/2020	19,649	5.74	112,785
	2/21/2020	60,091	4.54	272,813
	8/1/2020	47,778	2.45	117,056
Eric D. Batchelder (1)	2/21/2020	61,504	4.54	279,228
	7/11/2020	165,503	2.34	387,277

(1) In July 2020, Mr. Batchelder departed from his position as Executive Vice President and Chief Financial Officer. Pursuant to the terms of his award agreements and change in control agreement, Mr. Batchelder's outstanding restricted incentive units vested at 100% and a portion of his outstanding performance units vested at 16.8% of target in July 2020. The remaining outstanding performance units not vested in 2020 will vest on the original vesting date of January 1, 2022 and January 1, 2023, as applicable, depending on whether and to what extent the performance metrics thereunder are satisfied.

Payments Upon Termination or Change of Control

The following table shows potential payments that would have been made to the named executive officers as of December 31, 2020.

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	4,341,068	24,448	—	5,994,818	5,591,222
Benjamin D. Lamb	2,552,556	31,239	—	3,044,181	2,329,687
Pablo G. Mercado	2,191,666	29,667	—	2,619,166	1,484,000
Alaina K. Brooks	2,130,282	31,778	—	2,548,163	1,385,744
Eric D. Batchelder (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 and a half 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 2020.

(6) In July 2020, Mr. Batchelder departed from his position as Executive Vice President and Chief Financial Officer. Pursuant to his departure, Mr. Batchelder received a cash payment of $1,733,659 related to his Severance Benefit and accelerated vesting of outstanding equity awards valued at $387,277 as of the vesting date. In addition, Mr. Batchelder will receive a prorated amount related to his 2020 bonus, which is payable at the end of February 2021.

Compensation of Directors for Fiscal Year 2020

DIRECTOR COMPENSATION

Name	Fees Earned or Paid in Cash ($)	Unit Awards (1) ($)	All Other Compensation ($)(2)	Total ($)
Deborah G. Adams	51,174	29,586	7,236	87,996
James C. Crain	110,000	29,586	7,236	146,822
Leldon E. Echols	104,000	29,586	7,236	140,822
Kyle D. Vann	111,250	29,586	7,236	148,072

(1) On April 20, 2020, Ms. Adams and Messrs. Crain, Echols, and Vann were each granted awards of restricted incentive units with a fair market value of $1.15 per unit and that vested on January 1, 2021. The amounts shown represent the grant date fair value of awards computed in accordance with ASC 718. See "Item 8. Financial Statements and Supplementary Data—Note 11" for the assumptions made in our valuation of such awards. At December 31, 2020, Ms. Adams and Messrs. Crain, Echols, and Vann each held an aggregate of 25,727 outstanding restricted incentive unit awards. The number of units granted to each Director based on $4.47, the closing trading price on December 5, 2019, is consistent with the grants to Named Executive Officers. Value on this date aligns with Board approved compensation of equity compensation valued at $115,000.

(2) Other Compensation is comprised of DERs with respect to restricted incentive units.

Each director of the Managing Member who is not an employee of the Managing Member or GIP is paid an annual retainer fee of $72,500 and equity compensation valued at $115,000. Directors do not receive an attendance fee for each regularly scheduled quarterly board meeting or each additional meeting that they attend. The respective chairs of each committee received the following annual fees for fiscal year ended 2020: Audit—$24,000, Governance and Compensation Committee—$15,000, and Conflicts—$20,000. The respective members of each committee received the following annual fees for the fiscal year ended 2020: Audit—$17,500, Governance and Compensation Committee—$7,500, and Conflicts—$15,000. Directors were also reimbursed for related out-of-pocket expenses.

Barry E. Davis, as an officer of the Managing Member, William J. Brilliant, Thomas W. Horton, James K. Lee, and Scott E. Telesz, as representatives of GIP, and Richard P. Schifter, as a representative of TPG, receive no separate compensation for their respective service as directors.

Governance and Compensation Committee Interlocks and Insider Participation

Our Governance and Compensation 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 representative of GIP and may have an interest in the transactions among GIP, ENLK, and us. Please see "Item 13. Certain Relationships and Related Transactions, and Director Independence."

No other member of the Compensation Committee during fiscal 2020 was a current or former officer or employee of the General Partner or had any relationship requiring disclosure by us under Item 404 of Regulation S-K as adopted by the Commission. None of the 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 Board or the 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 has determined that having Barry E. Davis serve as Chairman and Chief Executive Officer is in our best interest at this time, and that such arrangement makes 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 will review the risk assessments with management and provide reports to the Board regarding the internal risk assessment processes, the risks identified, and the mitigation strategies planned or in place to address the risks in the business. The Board and the Audit Committee each provide insight into the issues, based on the experience of their members, and provide constructive challenges to management's assumptions and assertions.

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

EnLink Midstream, LLC Ownership

The following table shows the beneficial ownership of ENLC, as of February 11, 2021, held by:

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

The percentage of total ENLC common units beneficially owned is based on a total of 559,455,535 units (including 69,400,520 common units, which reflects the as-exchanged amount of the 60,348,278 ENLC Class C Common Units held by Enfield) as of February 11, 2021.

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)
Global Infrastructure Investors III, LLC (5)	224,355,359	45.78 %	—	—	224,355,359	40.10 %
Enfield Holdings Advisors, Inc. (6)	—	—	60,348,278	100 %	60,348,278	10.79 %
Invesco Ltd. (7)	45,729,797	9.33 %	—	—	45,729,797	8.17 %
Barry E. Davis (8)	3,085,417	*	—	—	3,085,417	*
Benjamin D. Lamb	418,753	*	—	—	418,753	*
Pablo G. Mercado (9)	—	*	—	—	—	*
Alaina K. Brooks	160,429	*	—	—	160,429	*
Eric D. Batchelder (10)	170,884	*	—	—	170,884	*
Deborah G. Adams	25,727	*		—	25,727	*
William J. Brilliant	—	*	—	—	—	*
James C. Crain (11)	120,667	*	—	—	120,667	*
Leldon E. Echols	115,752	*	—	—	115,752	*
Thomas W. Horton	—	*	—	—	—	*
James K. Lee	—	*	—	—	—	*
Richard P. Schifter	—	*	—	—	—	*
Scott E. Telesz	—	*	—	—	—	*
Kyle D. Vann	190,634	*	—	—	190,634	*
All directors and executive officers as a group (13 persons)	4,117,379	*	—	—	4,117,379	*

* Less than 1%

(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) The percentages reflected in the column below are based on a total of 490,055,015 common units.

(4) The percentages reflected in the column below are based on a total of 559,455,535 common units, which includes the units described in (3) above, and 69,400,520 common units, which reflects the as-exchanged amount of the 60,348,278 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) Based solely on the Amendment No. 2 to the Schedule 13D filed with the Commission on February 5, 2019 by Global Infrastructure Investors III, LLC ("Global Investors"). Such filing indicates that Global Investors, Global Infrastructure GP III, L.P. ("Global GP"), GIP III Stetson Aggregator II, L.P. ("Aggregator II"), GIP III Stetson Aggregator I, L.P. ("Aggregator I"), and GIP III Stetson GP, LLC ("Stetson GP") have shared voting and dispositive

power with respect to 224,355,359 ENLC common units, and that GIP III Stetson II, L.P. ("Stetson II") and GIP III Stetson I, L.P. ("Stetson I") are the record holders of 115,495,669 and 108,859,690 ENLC common units, respectively. Global Investors is the sole general partner of Global GP, which is the general partner of each of Aggregator I and Aggregator II, which are the managing members of Stetson GP, which is the general partner of each of Stetson I and Stetson II. As a result, Global Investors, Global GP, Aggregator I, Aggregator II and Stetson GP may be deemed to share beneficial ownership of the ENLC common units beneficially owned by Stetson I and Stetson II. 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 ENLC common units beneficially owned by Global Investors. Such individuals expressly disclaim any such beneficial ownership. The address of each of Global Investors, Global GP, Aggregator II, Aggregator I, Stetson GP, Stetson I, Stetson II, 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.

(6) Based solely on the Schedule 13D filed with the Commission on February 4, 2019 by Enfield Holdings Advisors, Inc. ("Enfield Holdings Advisors"), the Schedule 13D filed with the Commission on February 5, 2019 by The Goldman Sachs Group, Inc. ("GS Group"), and the Schedule 13D filed with the Commission on February 4, 2019 by TPG Advisors VII, Inc. ("TPG Advisors VII"). Such filings indicate that Enfield and Enfield Holdings Advisors, the general partner of Enfield, have shared voting and dispositive power with respect to the securities held by Enfield Holdings reported herein. The address of each of Enfield and Enfield Holdings Advisors in c/o TPG Global, LLC ("TPG Global"), 301 Commerce Street, Suite 3300, Fort Worth, Texas 76102. Affiliates of the GS Group and affiliates of TPG Global each respectively hold 100 shares of common stock, and have appointed one of the two board members of, Enfield Holdings Advisors. TPG Advisors VII holds 100 shares of common stock, and has appointed one of the two board members, of Enfield Holdings Advisors. Because of the relationship of TPG Advisors VII to Enfield Holdings, TPG Advisors VII may be deemed to beneficially own the securities held by Enfield Holdings reported herein. David Bonderman and James C. Coulter are sole shareholders of TPG Advisors VII. Because of the relationship of Messrs. Bonderman and Coulter to TPG Advisors VII, each of Messrs. Bonderman and Coulter may be deemed to beneficially own the securities held by Enfield Holdings reported herein. Messrs. Bonderman and Coulter disclaim beneficial ownership of the securities held by Enfield Holdings reported herein except to the extent of their pecuniary interest therein. The address of TPG Advisors VII and Messrs. Bonderman and Coulter is c/o TPG Global, 301 Commerce Street, Suite 3300, Fort Worth, Texas 76102. GS Group, Goldman Sachs & Co. LLC ("Goldman Sachs"), West Street International Infrastructure Partners III, L.P. ("WS International"), West Street European Infrastructure Partners III, L.P. ("WS European"), West Street Global Infrastructure Partners III, L.P. ("WS Global"), Broad Street Principal Investments, L.L.C. ("BS Principal"), West Street Energy Partners Offshore - B AIV-1, L.P. ("WS Offshore B"), West Street Energy Partners AIV-1, L.P. ("WS AIV"), West Street Energy Partners Offshore AIV-1, L.P. ("WS Offshore AIV"), West Street Energy Partners Offshore Holding - B AIV-1, L.P. ("WS Holdings B"), Broad Street Infrastructure Advisors III, L.L.C. ("BS Infrastructure"), and Broad Street Energy Advisors AIV-1, L.L.C. ("BS Energy AIV," and together with the GS Group, Goldman Sachs, WS International, WS European, WS Global, BS Principal, WS Offshore B, WS AIV, WS Offshore AIV, WS Holdings B, and BS Infrastructure, the "GS Entities") are the direct or indirect beneficial owners of WSIP Egypt Holdings, LP ("WSIP") and WSEP Egypt Holdings, LP ("WSEP"), which hold 100 shares of common stock, and have appointed one of the two directors, of Enfield Holdings Advisors. Because of the relationship by and between the GS Entities, WSIP and WSEP on the one hand and Enfield Holdings on the other hand, the GS Entities, WSIP and WSEP may be deemed to share beneficial ownership of the securities held by Enfield Holdings reported herein. The address of each of the GS Entities, WSIP and WSEP is 200 West Street New York, NY 10282-2198. Additionally, as of February 1, 2019, GS Group and Goldman Sachs may be deemed to share beneficial ownership of 695,632 ENLC common units acquired by Goldman Sachs or another wholly-owned broker or dealer subsidiary of GS Group in ordinary course trading activities, and 3,186 ENLC common units held in client accounts with respect to which Goldman Sachs or another wholly-owned subsidiary of GS Group or their employees have investment discretion.

(7) Based solely on the Schedule 13G filed with the Commission on February 9, 2021 by Invesco Ltd. ("Invesco"). Such filing indicates that Invesco has sole voting and dispositive power with respect to 45,729,797 ENLC common units. The address of Invesco is 1555 Peachtree Street NE, Suite 1800, Atlanta, GA 30309.

(8) 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.

(9) On July 13, 2020, Mr. Mercado was appointed Executive Vice President and Chief Financial Officer and was awarded restricted incentive units at the time of his appointment, which are scheduled to vest on July 13, 2023.

(10) In July 2020, Mr. Batchelder departed from his position as Executive Vice President and Chief Financial Officer.

(11) Of these ENLC common units, 1,000 are held by the James C. Crain Trust, Mr. James C. Crain as trustee, for the benefit of Mr. Crain's children, and Mr. Crain disclaims beneficial ownership of these securities except to the extent of his pecuniary interest therein.

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

GIP has pledged all of the equity interests that it owns in ENLC and the 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 the Managing Member and would allow the new owner to replace the board of directors and officers of the Managing Member 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 the 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 the Managing Member."

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)	7,701,327 (2)	N/A	30,222,302 (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 our unitholders in March 2014 for the benefit of our officers, employees, and directors, and the GP Plan, which was approved by ENLK's unitholders effective April 6, 2016 for the benefit of ENLK's 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. Effective as of December 28, 2020, with the approval of a majority of our unitholders, we amended and restated the 2014 Plan to increase the number of common units reserved for issuance to 41,116,046.

(2) The number of securities includes 4,729,922 restricted units that have been granted under the 2014 Plan that have not vested and 620,164 restricted units that have been granted under the GP Plan that have not vested. In addition, the number of securities includes 2,257,712 performance unit awards that have been granted under the 2014 Plan, assuming the target distribution at the time of vesting, and 93,529 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. Additionally, effective as of September 17, 2020, the 2014 Plan, as amended, provided for the issuance of an additional 20,000,00 common units, which altogether provided for the issuance of a total 41,116,046 under the 2014 Plan. Of the 41,116,046 common units that may be awarded under the 2014 Plan, 30,222,302 common units remained eligible for future grants as of December 31, 2020. After 2021 awards were made on January 1, 2021, 26,655,865 common units remain eligible for future grants.

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

Relationship with EnLink Midstream Partners, LP

In connection with the Merger, we issued 304,822,035 common units to acquire all of the outstanding ENLK common units not previously owned by us. Subsequent to the Merger, ENLC owns all of ENLK's common units and also owns all of the membership interests of the General Partner, which allows us to appoint all of the officers and directors of the General Partner and to manage and operate ENLK. As of the closing date of the Merger, the price of our common units was $10.53 per unit.

Relationship with GIP

We are managed by our Managing Member, which is wholly-owned by GIP. Therefore, GIP controls us and our ability to manage and operate our business. Additionally, four of our directors, William J. Brilliant, Thomas W. Horton, James K. Lee, and Scott E. Telesz are representatives of GIP. Those individuals do not receive separate compensation for their service on the Board, but they are entitled to indemnification related to their service as directors pursuant to the indemnification agreements as described below. For the year ended December 31, 2020, we recorded general and administrative expenses of $0.2 million related to personnel secondment services provided by GIP. Expenses related to transactions with GIP were not material for the years ended December 31, 2019 and 2018.

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 our board of directors, TPG or Goldman Sachs, which are the owners of Enfield, the beneficial owner of ENLK’s 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 Managing Member’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 or is or was serving at the request of us, the General Partner, or the Managing Member 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. 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 operating agreement. Pursuant to our Code of Ethics, the Audit Committee of the Board must approve any transaction, arrangement, or relationship, or any series of similar transactions, arrangements, or relationships, in which we or any of our 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 ENLC’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 Managing Member or its affiliates, on the one hand, and ENLC and certain of its affiliates, on the other hand, the Managing Member will resolve that conflict in accordance with the provisions of our operating agreement. The Managing Member 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 or the approval of a majority of the unitholders (excluding units owned by the Managing Member and its affiliates). Any resolution, course of action, or transaction receiving approval of a majority of the members of the Conflicts Committee of the Board or approval of a majority of the unitholders (excluding units owned by the Managing Member and its affiliates) will be conclusively deemed to be approved by ENLC and all of its members.

Director Independence

See “Item 10. Directors, Executive Officers, and Corporate Governance” for information regarding director independence.

Item 14. Principal Accountant Fees and Services

Audit Fees

The fees for professional services rendered for the audit of our annual financial statements for the fiscal years ended December 31, 2020, 2019, and 2018, review of our internal control procedures for the fiscal years ended December 31, 2020, 2019, and 2018, 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 $2.5 million, $2.6 million, and $2.1 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, 2020, 2019, and 2018 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, 2020, 2019, and 2018, 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, 2020, 2019, and 2018.

Audit Committee Approval of Audit and Non-Audit Services

All audit and non-audit services and any services that exceed the annual limits set forth in our annual engagement letter for audit services must be pre-approved by the Audit Committee. The Chairman of the Audit Committee is authorized by the Audit Committee to pre-approve additional KPMG audit and non-audit services between meetings of the 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 Audit Committee at its next meeting. For the years ended December 31, 2019 and 2018, the 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. 001-36336).
3.1		—	Certificate of Formation of EnLink Midstream, LLC (incorporated by reference to Exhibit 3.1 to our Registration Statement on Form S-4, filed with the Commission on November 20, 2013, file No. 333-192419).
3.2		—	Certificate of Amendment to Certificate of Formation of EnLink Midstream, LLC (incorporated by reference to Exhibit 3.2 to Amendment No. 2 to our Registration Statement on Form S-4, filed with the Commission on January 21, 2014, file No. 333-192419).
3.3		—	Second Amended and Restated Operating Agreement of EnLink Midstream, LLC, 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. 001-36336).
3.4		—	Certificate of Formation of EnLink Midstream Manager, LLC (incorporated by reference to Exhibit 3.12 to our Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2014, filed with the Commission on August 6, 2014, file No. 001-36336).
3.5		—	Certificate of Amendment to the Certificate of Formation of EnLink Midstream Manager, LLC (incorporated by reference to Exhibit 3.13 to our Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2014, filed with the Commission on August 6, 2014, file No. 001-36336).
3.6		—	Second Amended and Restated Limited Liability Company Agreement of EnLink Midstream Manager, 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. 001-36336).
3.7		—	Certificate of Formation of EnLink Midstream GP, LLC (incorporated by reference to Exhibit 3.7 to EnLink Midstream Partners, LP's Registration Statement on Form S-1, file No. 333-97779).
3.8		—	Certificate of Amendment to the Certificate of Formation of EnLink Midstream GP, LLC (incorporated by reference to Exhibit 3.12 to EnLink Midstream Partners, LP's Registration Statement on Form S-3, filed with the Commission on March 10, 2014, file No. 333-194465).
3.9		—	Fourth Amended and Restated Limited Liability Company Agreement of EnLink Midstream GP, LLC, dated as of July 18, 2018 (incorporated by reference to Exhibit 3.2 to our Current Report on Form 8-K dated July 17, 2018, filed with the Commission on July 23, 2018, file No. 001-36336).
3.10		—	Certificate of Limited Partnership of EnLink Midstream Partners, LP (incorporated by reference to Exhibit 3.1 to EnLink Midstream Partners, LP's Registration Statement on Form S-1, filed with the Commission on August 7, 2002, file No. 333-97779).
3.11		—	Certificate of Amendment to the Certificate of Limited Partnership of EnLink Midstream Partners, LP (incorporated by reference to Exhibit 3.2 to EnLink Midstream Partners, LP's 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).
3.12		—	Second Amendment to the Certificate of Limited Partnership of EnLink Midstream Partners, LP (incorporated by reference to Exhibit 3.3 to EnLink Midstream Partners, LP's Current Report on Form 8-K dated March 6, 2014, filed with the Commission on March 11, 2014, file No. 001-36340).
3.13		—	Third Amendment to the Certificate of Limited Partnership of EnLink Midstream Partners, LP (incorporated by reference to Exhibit 3.1 to EnLink Midstream Partners, LP's Current Report on Form 8-K dated June 16, 2017, filed with the Commission on June 19, 2017, file No. 001-36340).
3.14		—	Tenth Amended and Restated Agreement of Limited Partnership of EnLink Midstream Partners, LP, dated as of January 25, 2019 (incorporated by reference to Exhibit 3.2 to our Current Report on Form 8-K dated January 25, 2019, filed with the Commission on January 29, 2019, file No. 001-36336).

4.1		—	Registration Rights Agreement, dated as of March 7, 2014, by and among Devon Gas Services, L.P., EnLink Midstream, LLC and, pursuant to a joinder thereto, dated as of July 18, 2018, GIP III Stetson II, L.P. (incorporated by reference to Exhibit 4.1 to our Current Report on Form 8-K dated March 7, 2014, filed with the Commission on March 11, 2014, file No. 001-36336).
4.2		—	Amended and Restated Registration Rights Agreement, dated as of January 25, 2019, by and between EnLink Midstream, LLC and Enfield Holdings, L.P. (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. 001-36336).
4.3		—	Registration Rights Agreement, dated as of January 7, 2016, by and among EnLink Midstream, LLC, Tall Oak Midstream, LLC and FE-STACK, LLC (incorporated by reference to Exhibit 4.2 to our Current Report on Form 8-K dated January 7, 2016, filed with the Commission on January 12, 2016, file No. 001-36336).
4.4		—	Specimen Certificate representing common units (incorporated by reference to Exhibit 5 to our Registration Statement on Form 8-A, filed with the Commission on March 6, 2014, file No. 001-36336).
4.5		—	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 EnLink Midstream Partners, LP's Current Report on Form 8-K dated March 19, 2014, filed with the Commission on March 21, 2014, file No. 001-36340).
4.6		—	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 EnLink Midstream Partners, LP's Current Report on Form 8-K dated March 19, 2014, filed with the Commission on March 21, 2014, file No. 001-36340).
4.7		—	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 EnLink Midstream Partners, LP's Current Report on Form 8-K dated November 6, 2014, filed with the Commission on November 12, 2014, file No. 001-36340).
4.8		—	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 EnLink Midstream Partners, LP's Current Report on Form 8-K dated May 7, 2015, filed with the Commission on May 12, 2015, file No. 001-36340).
4.9		—	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 EnLink Midstream Partners, LP's Current Report on Form 8-K dated July 11, 2016, filed with the Commission on July 14, 2016, file No. 001-36340).
4.10		—	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 EnLink Midstream Partners, LP's Current Report on Form 8-K dated May 11, 2017, filed with the Commission on May 11, 2017, file No. 001-36340).
4.11		—	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. 001-36336).
4.12		—	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. 001-36336).
4.13		—	Indenture, dated as of December 17, 2020, by and among EnLink Midstream, LLC, as issuer, EnLink Midstream Partners, LP, as guarantor, and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.1 to our Current Report on Form 8-K dated December 14, 2020, filed with the Commission on December 18, 2020, file No. 001-36336).
4.14	*	—	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. 001-36336).
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 our 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 December 28, 2020 (the "2014 Plan") (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K dated December 7, 2020 filed with the Commission on December 9, 2020, file No. 001-36336).
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 10.6 to our Annual Report on Form 10-K dated December 31, 2018, filed with the Commission on February 20, 2019, file No. 001-36336).

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 our 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 10.2 to our Current Report on Form 8-K dated December 11, 2018, filed with the Commission on December 12, 2018, file No. 001-36336).
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 10.2 to our Current Report on Form 8-K dated January 25, 2019, filed with the Commission on January 29, 2019, file No. 001-36336).
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 10.3 to our Current Report on Form 8-K dated January 25, 2019, filed with the Commission on January 29, 2019, file No. 001-36336).
10.9		—	Guaranty Agreement, dated as of January 25, 2019, by EnLink Midstream Partners, LP in favor of Bank of America, 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 10.4 to our Current Report on Form 8-K dated January 25, 2019, filed with the Commission on January 29, 2019, file No. 001-36336).
10.10		—	Amended and Restated Board Representation Agreement, dated as of January 25, 2019, by and among EnLink Midstream, LLC, EnLink Midstream Manager, LLC, GIP III Stetson I, L.P., and TPG VII Management, LLC (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 25,2019, file No. 001-36336).
10.11	†	—	Form of Performance Unit Agreement made under the GP Plan (incorporated by reference to Exhibit 10.1 to EnLink Midstream Partners, LP's Quarterly Report on Form 10-Q for the quarter ended March 31, 2017, file No. 001-36340).
10.12	†	—	Form of Performance Unit Agreement made under the 2014 Plan (incorporated by reference to Exhibit 10.2 to EnLink Midstream Partners, LP's Quarterly Report on Form 10-Q for the quarter ended March 31, 2017, file No. 001-36340).
10.13	†	—	Form of Restricted Incentive Unit Agreement made under the GP Plan (incorporated by reference to Exhibit 10.3 to EnLink Midstream Partners, LP's Quarterly Report on Form 10-Q for the quarter ended March 31, 2017, file No. 001-36340).
10.14	†	—	Form of Restricted Incentive Unit Agreement made under the 2014 Plan (incorporated by reference to Exhibit 10.4 to EnLink Midstream Partners, LP's 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 10.1 to our Current Report on Form 8-K dated March 8, 2019, filed with the Commission March 14, 2019, file No. 001-36336).
10.16	†	—	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. 001-36336).
10.17	*†	—	Form of Performance Unit Agreement made under the 2014 Plan.
10.18	†	—	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. 001-36336).
10.19	†	—	Form of EnLink Midstream Operating, LP Amended and Restated Change in Control Agreement (incorporated by reference to Exhibit 10.3 to our Quarterly Report on Form 10-Q for the quarter ended September 30, 2020, file No. 001-36336).
10.20		—	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).

10.21		—	Sale and Contribution Agreement, dated as of October 21, 2020, by and among EnLink Midstream Funding, LLC, EnLink Midstream Operating, LP, and the originators from time to time party thereto (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K dated October 21, 2020, filed with the Commission on October 22, 2020, file No. 001-36336).
10.22		—	Receivables Financing Agreement, dated as of October 21, 2020, by and among EnLink Midstream Funding, LLC, as borrower, EnLink Midstream Operating, LP, as initial servicer, PNC Bank, National Association, as administrative agent and lender, the lenders party thereto, and PNC Capital Markets, LLC, as structuring agent (incorporated by reference to Exhibit 10.2 to our Current Report on Form 8-K dated October 21, 2020, filed with the Commission on October 22, 2020, file No. 001-36336).
21.1	*	—	List of Subsidiaries.
22.1	*	—	Subsidiary Guarantors.
23.1	*	—	Consent of KPMG LLP.
31.1	*	—	Certification of the Principal Executive Officer.
31.2	*	—	Certification of the Principal Financial Officer.
32.1	*	—	Certification of the Principal Executive Officer and the Principal Financial Officer of the Partnership pursuant to 18 U.S.C. Section 1350.
101	*	—	The following financial information from EnLink Midstream, LLC's Annual Report on Form 10-K for the year ended December 31, 2020, formatted in iXBRL (Inline eXtensible Business Reporting Language): (i) Consolidated Balance Sheets as of December 31, 2020 and December 31, 2019, (ii) Consolidated Statements of Operations for the years ended December 31, 2020, 2019, and 2018, (iii) Consolidated Statements of Changes in Members' Equity for the years ended December 31, 2020, 2019, and 2018, (iv) Consolidated Statements of Cash Flows for the years ended December 31, 2020, 2019, and 2018, 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 Exhibit 2.1 are not filed herewith. The agreement identifies 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, LLC

By: EnLink Midstream Manager, LLC, its managing member

February 17, 2021

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 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 17, 2021
/s/ DEBORAH G. ADAMS Deborah G. Adams	Director	February 17, 2021
/s/ WILLIAM J. BRILLIANT William J. Brilliant	Director	February 17, 2021
/s/ JAMES C. CRAIN James C. Crain	Director	February 17, 2021
/s/ LELDON E. ECHOLS Leldon E. Echols	Director	February 17, 2021
/s/ THOMAS W. HORTON Thomas W. Horton	Director	February 17, 2021
/s/ JAMES K. LEE James K. Lee	Director	February 17, 2021
/s/ RICHARD P. SCHIFTER Richard P. Schifter	Director	February 17, 2021
/s/ SCOTT E. TELESZ Scott E. Telesz	Director	February 17, 2021
/s/ KYLE D. VANN Kyle D. Vann	Director	February 17, 2021
/s/ PABLO G. MERCADO Pablo G. Mercado	Executive Vice President and Chief Financial Officer (Principal Financial Officer)	February 17, 2021
/s/ J. PHILIPP ROSSBACH J. Philipp Rossbach	Vice President and Chief Accounting Officer (Principal Accounting Officer)	February 17, 2021

Exhibit 4.14

ENLINK MIDSTREAM, LLC
DESCRIPTION OF SECURITIES

EnLink Midstream LLC ("*we*" or "*ENLC*") has two classes of securities registered under Section 12 of the Securities Exchange Act of 1934, as amended (the "*Exchange Act*"): (i) common units representing non-managing membership interests in ENLC (the "*common units*") and (ii) 5.375% senior unsecured notes due 2029 (the "*notes*").

DESCRIPTION OF COMMON UNITS

General

Our common units represent non-managing membership interests in ENLC. Our unitholders are entitled to participate in cash distributions and exercise the rights and privileges available to non-managing members under our Second Amended and Restated Operating Agreement, dated as of January 25, 2019 (the "*operating agreement*"). The following summary of our common units, our certificate of formation, and our operating agreement does not purport to be complete and is qualified in its entirety by reference to the provisions of applicable law and to the full text of our certificate of formation (as amended) and our operating agreement, which are filed as Exhibits 3.1 and 3.3, respectively, to ENLC's Registration Statement on Form S-4, filed with the U.S. Securities and Exchange Commission (the "*SEC*") on November 20, 2013, file No. 333-192419). Our common units are traded on the NYSE under the symbol "ENLC."

Transfer Agent and Registrar

Duties

American Stock Transfer & Trust Company, LLC serves as registrar and transfer agent for our common units. We pay all fees charged by the transfer agent for transfers of our common units except the following, which must be paid by our unitholders:

- surety bond premiums to replace lost or stolen certificates, taxes, and other governmental charges;
- special charges for services requested by a unitholder; and
- other similar fees or charges.

There will be no charge to our unitholders for disbursements of cash distributions by us. We will indemnify the transfer agent, its agents, and each of their stockholders, directors, officers, and employees against all claims and losses that may arise out of acts performed or omitted for its activities in that capacity, except for any liability due to any gross negligence or intentional misconduct of the indemnified person or entity.

Resignation or Removal

The transfer agent may resign by providing us notice. We may also remove the transfer agent. The resignation or removal of the transfer agent will become effective upon our appointment of a successor transfer agent and registrar and its acceptance of the appointment. If no successor is appointed, our managing member may act as the transfer agent and registrar until a successor is appointed.

Transfer of Our Common Units

By transfer of our common units in accordance with our operating agreement, each transferee of our common units will be admitted as a non-managing member with respect to our common units transferred when such transfer is reflected in our books and records and such transferee becomes the record holder of our common units transferred. Each transferee:

- represents that the transferee has the capacity, power, and authority to become bound by our operating agreement;
- automatically becomes bound by the terms of our operating agreement; and
- gives the consents, acknowledgements, and waivers contained in our operating agreement, such as the approval of all transactions and agreements entered into in connection with our formation.

Our board of directors will cause any transfers to be recorded on our books and records from time to time as necessary to ensure their accuracy.

We may, at our discretion, treat the nominee holder of any of our common units as the absolute owner. In that case, the beneficial holder's rights are limited solely to those that it has against the nominee holder as a result of any agreement between the beneficial owner and the nominee holder.

Our common units are securities and any transfers are subject to the laws governing transfer of securities. In addition to other rights acquired upon transfer, the transferor gives the transferee the right to become a non-managing member for the transferred common units.

Until any common unit has been transferred on our books, we and the transfer agent may treat the record holder of the common unit as the absolute owner for all purposes, except as otherwise required by law or stock exchange regulations.

DESCRIPTION OF OUR OPERATING AGREEMENT

The following is a summary of the material provisions of our operating agreement.

Organization and Duration

We were organized on October 16, 2013 and will have a perpetual existence unless terminated pursuant to the terms of our operating agreement.

Purpose

Our purpose, as set forth in our operating agreement is limited to any business activity that is approved by our managing member, in its sole discretion, and that lawfully may be conducted by a limited liability company organized under Delaware law. Although our managing member has the ability to cause us and our subsidiaries to engage in activities other than the business of owning, operating, developing, and acquiring crude oil and natural gas gathering and processing assets and the owning of equity securities in EnLink Midstream Partners, LP ("*ENLK*"), our managing member may decline to do so in its sole discretion. Our managing member is generally authorized to perform all acts it determines to be necessary or appropriate to carry out the purposes of, and to conduct, our business.

Capital Contributions

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

Voting Rights

The following is a summary of the unitholder vote required for approval of the matters specified below. Matters that require the approval of a "unit majority" require the approval of a majority of the common units and our Class C common units representing limited liability company interests in us (the "*Class C Common Units*" and, together with our common units, the "*ENLC Units*"), voting together as a single class. Each Class C Common Unit will be entitled to the number of votes equal to the number of common units into which a Series B Cumulative Convertible Preferred Unit representing a limited partner interest in ENLK (an "*ENLK Series B Unit*") is then exchangeable (which is the product of the number of ENLK Series B Units being exchanged multiplied by 1.15 (subject to certain adjustments)). In addition, the holders of Class C Common Units are entitled to vote as a separate class on any matter that (i) adversely affects the rights, preferences, and privileges of the Class C Common Units or the ENLK Series B Units, including certain minority protections with respect to substantially the same matters for which the holders of ENLK Series B Units have approval rights under the limited partnership agreement of ENLK, or (ii) amends or modifies any of the terms of the Class C Common Units or ENLK Series B Units. The approval of a majority of the Class C Common Units is required to approve any matter for which the holders of Class C Common Units are entitled to vote as a separate class.

In voting their common units, affiliates of our managing member will have no duty or obligation whatsoever to us or our members, including any duty to act in our best interest or the best interests of our members.

Matter	Vote Requirement
Issuance of additional units	No approval right.
Amendment of the operating agreement	Certain amendments may be made by our managing member without the approval of the unitholders. Other amendments generally require the approval of a unit majority. See "–Amendment of the Operating Agreement."
Merger of or the sale of all or substantially all of our assets	Unit majority in certain circumstances. See "–Merger, Consolidation, Conversion, Sale, or Other Disposition of Assets."
Dissolution of EnLink Midstream	Unit majority. See "–Dissolution."
Continuation of our business upon dissolution	Unit majority. See "–Dissolution."
Withdrawal of our managing member	No approval right. See "–Withdrawal or Removal of Our Managing Member."
Removal of our managing member	Not less than 66 2/3 % of the outstanding ENLC Units, voting as a single class, including units held by our managing member and its affiliates. See "–Withdrawal or Removal of Our Managing Member."
Transfer of ownership interests in our managing member	No approval right. See "–Transfer of Ownership Interests in Our Managing Member."
Transfer of the interest of our managing member	No approval right. See "–Transfer of Managing Member Interest."

If any person or group other than our managing member and its affiliates acquires beneficial ownership of 20% or more of any class of units, that person or group loses voting rights on all of its units. This loss of voting rights does not apply to any person or group that acquires the units from our managing member or its affiliates (other than us) and any transferees of that person or group approved by our managing member or to any person or group who acquires the units with the written approval of our managing member, including Enfield Holdings, L.P., as the holder of the Class C Common Units and the ENLK Series B Units.

Applicable Law; Forum, Venue, and Jurisdiction

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

- arising out of or relating in any way to our operating agreement (including any claims, suits, or actions to interpret, apply, or enforce the provisions of our operating agreement or the duties, obligations, or liabilities among our members, or the rights or powers of, or restrictions on, us or our members);
- brought in a derivative manner on our behalf;
- asserting a claim of breach of a fiduciary duty or other duty owed by any of our or our managing member's directors, officers, or other employees, or owed by our managing member, to us or our members;
- asserting a claim arising pursuant to any provision of the Delaware Limited Liability Company Act (the "*DLLCA*"); or
- asserting a claim governed by the internal affairs doctrine;

shall be exclusively brought in the Court of Chancery of the State of Delaware (or, if such court does not have subject matter jurisdiction thereof, any other court located in the State of Delaware with subject matter jurisdiction), regardless of whether such claims, suits, actions, or proceedings sound in contract, tort, fraud, or otherwise, are based on common law, statutory, equitable, legal, or other grounds, or are derivative or direct claims.

By acquiring our common units, holders of our common units irrevocably consent to these limitations and provisions regarding claims, suits, actions, or proceedings and submitting to the exclusive jurisdiction of the Court of Chancery of the State of Delaware (or such other Delaware courts with subject matter jurisdiction) in connection with any such claims, suits, actions, or proceedings.

Limited Liability

Under the DLLCA, a limited liability company may not make a distribution to a member if, after the distribution, all liabilities of the limited liability company, other than liabilities to members on account of their membership interests and liabilities for which the recourse of creditors is limited to specific property of the company, would exceed the fair value of the assets of the limited liability company. For the purpose of determining the fair value of the assets of a limited liability company, the DLLCA 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 liability company only to the extent that the fair value of that property exceeds the non-recourse liability. The DLLCA provides that a member who receives a distribution and knew at the time of the distribution that the distribution was in violation of the DLLCA shall be liable to the limited liability company for the amount of the distribution for three years. Under the DLLCA, an assignee who becomes a substituted unitholder of a company is liable for the obligations of his assignor to make contributions to the company, except the assignee is not obligated for liabilities unknown to him at the time he became a unitholder and that could not be ascertained from the limited liability company agreement.

Issuance of Additional Interests

Our operating agreement authorizes us to issue an unlimited number of additional membership interests for the consideration and on the terms and conditions determined by our managing member without the approval of our unitholders, except that our operating agreement restricts our ability to issue any membership interests senior to or on parity with the ENLK Series B Units with respect to distributions on such membership interests or upon liquidation without the affirmative vote of the holders of a majority of our outstanding Class C Common Units, voting separately as a class.

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

In accordance with Delaware law and the provisions of our operating agreement, we may also issue additional membership interests that, as determined by our managing member, may have rights to distributions or special voting rights to which our common units are not entitled. In addition, except as described above with respect to the ENLK Series B Units, our operating agreement does not prohibit our subsidiaries from issuing equity interests, which may effectively rank senior to our common units.

Class C Common Units

The holders of Class C Common Units are not entitled to distributions thereon of any kind. For each additional ENLK Series B Unit issued by ENLK pursuant to limited partnership agreement of ENLK, we will issue an additional Class C Common Unit to the applicable holder of ENLK Series B Units pursuant to our operating agreement, so that the number of Class C Common Units issued and outstanding will always equal the number of ENLK Series B Units issued and outstanding. In addition, upon any exchange of ENLK Series B Units for our common units, a number of Class C Common Units equal to the number of ENLK Series B Units subject to such exchange will be cancelled.

The voting rights of the Class C Common Units are described under "–Voting Rights" above.

Amendment of the Operating Agreement

Amendments to our operating agreement may be proposed only by our managing member. However, to the fullest extent permitted by law, our managing member will have no duty or obligation to propose or approve any amendment and may decline to do so free of any duty or obligation whatsoever to us or our members, including any duty to act in our best interest or in the best interest of our members. In order to adopt a proposed amendment, other than the amendments discussed below, our managing member is required to seek written approval of the holders of the number of common units required to approve the amendment or to call a meeting of the members to consider and vote upon the proposed amendment. Except as described below, an amendment must be approved by a unitholder majority.

Prohibited Amendments. No amendment may be made that would:

- enlarge the obligations of any non-managing member without its consent, unless approved by at least a majority of the type or class of non-managing membership interests so affected; or

- enlarge the obligations of, restrict, change, or modify in any way any action by or rights of, or reduce in any way the amounts distributable, reimbursable, or otherwise payable to our managing member or any of its affiliates without the consent of our managing member, which consent may be given or withheld at its option.

The provision of our operating agreement preventing the amendments having the effects described in the clauses above can be amended upon the approval of the holders of at least 90% of the outstanding ENLC Units, voting together as a single class (including ENLC Units owned by our managing member and its affiliates).

Without Unitholder Approval. Our managing member may generally make amendments to our operating agreement without the approval of any member to reflect:

- a change in our name, the location of our principal place of business, our registered agent, or our registered office;

- the admission, substitution, withdrawal, or removal of members in accordance with our operating agreement;

- a change that our managing member determines to be necessary or appropriate to qualify or continue our qualification as a limited liability company or other entity in which the members have limited liability under the laws of any state;

- an amendment that is necessary, in the opinion of our legal counsel, to prevent us or our managing member, or its directors, officers, agents, or trustees from in any manner being subjected to the provisions of the Investment Company Act of 1940, the Investment Advisers Act of 1940, or "plan asset" regulations adopted under the Employee Retirement Income Security Act of 1974 ("ERISA"), whether or not substantially similar to plan asset regulations currently applied or proposed;

- an amendment that our managing member determines to be necessary or appropriate in connection with the creation, authorization, or issuance of additional membership interests or derivative instruments related to, convertible into, or exchangeable for additional membership interests;

- any amendment expressly permitted in our operating agreement to be made by our managing member acting alone;

- an amendment effected, necessitated, or contemplated by a merger agreement that has been approved under the terms of our operating agreement;

- any amendment that our managing member determines to be necessary or appropriate to reflect and account for the formation by us of, or our investment in, any corporation, partnership, or other entity, in connection with conduct otherwise permitted by our operating agreement;

- a change in our fiscal year or taxable period and related changes;

- conversions into, mergers with, or conveyances to another limited liability entity that is newly formed and has no assets, liabilities, or operations at the time of the conversion, merger, or conveyance other than those it receives by way of the conversion, merger, or conveyance; or

- any other amendments substantially similar to any of the matters described in the clauses above or in the clauses that immediately follow.

In addition, our managing member may make amendments to our operating agreement, without the approval of any member, if our managing member determines that those amendments:

- do not adversely affect the non-managing members, including any particular class of non-managing members, in any material respect;

- are necessary or appropriate to satisfy any requirements, conditions, or guidelines contained in any opinion, directive, order, ruling, or regulation of any federal or state agency or judicial authority or contained in any federal or state statute;

- are necessary or appropriate to facilitate the trading of membership interests or to comply with any rule, regulation, guideline, or requirement of any securities exchange on which the membership interests are or will be listed or admitted to trading;

- are necessary or appropriate in connection with any action taken by our managing member relating to splits or combinations of units under the provisions of our operating agreement; or

- are required to effect the intent expressed in this prospectus or the intent of the provisions of our operating agreement or are otherwise contemplated by our operating agreement.

***With Unitholder Approval*.** In addition to the above restrictions:

- any amendment that our managing member determines adversely affects, in any material respect, one or more particular classes of members will require the approval of at least a majority of the class or classes so affected, but no vote will be required by any class or classes of members that our managing member determines are not adversely affected in any material respect;

- any amendment that would have a material adverse effect on the rights or preferences of any type or class of outstanding ENLC Units in relation to other classes of common units will require the approval of at least a majority of the type or class of ENLC Units so affected;

- any amendment that would reduce the voting percentage required to take any action other than to remove our managing member or call a meeting of our unitholders is required to be approved by the affirmative vote of members whose aggregate outstanding ENLC Units constitute not less than the voting requirement sought to be reduced; and

- any amendment that would increase the percentage of ENLC Units required to remove our managing member or call a meeting of our unitholders must be approved by the affirmative vote of members whose aggregate outstanding units constitute not less than the percentage sought to be increased.

***Opinion of Counsel*.** For amendments of the type not requiring approval of a unitholder majority, our managing member will not be required to obtain an opinion of counsel that an amendment will not result in a loss of limited liability to the members in connection with any of the amendments. No other amendments to our operating agreement will become effective without the approval of holders of at least 90% of the outstanding ENLC Units, voting as a single class, unless we first obtain an opinion of counsel to the effect that the amendment will not affect the limited liability of any of its members under applicable law.

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

A merger, consolidation, or conversion of ENLC requires the prior consent of our managing member. However, our managing member will have no duty or obligation to consent to any merger, consolidation, or conversion and may decline to do so in its sole discretion.

In addition, our operating agreement generally prohibits our managing member from causing us to sell, exchange, or otherwise dispose of all or substantially all of (i) our assets and the assets of our subsidiaries, taken as a whole, or (ii) for so long as our Class C Common Units remain outstanding, the assets of ENLK and its subsidiaries, taken as a whole, in a single transaction or a series of related transactions, without the prior approval of the holders of a majority of the ENLC Units. Our managing member may, however, mortgage, pledge, hypothecate, or grant a security interest in all or substantially all of our assets and the assets of our subsidiaries or the assets of ENLK and its subsidiaries, taken as a whole, without such approval. Our managing member may also sell all or substantially all of our assets and our subsidiaries' assets or the assets of ENLK and its subsidiaries, taken as a whole, under a foreclosure or other realization upon those encumbrances without such approval. Finally, our managing member may consummate any merger without the prior approval of our members if (i) we are the surviving entity in the transaction, (ii) our managing member has received an opinion of counsel regarding limited liability matters, (iii) the transaction would not result in an amendment to our operating agreement (other than an amendment that our managing member could adopt without the consent of our unitholders), (iv) each of our common units would be an identical unit of ours following the transaction, and (v) the membership securities to be issued in the transaction do not exceed 20% of the outstanding membership interests immediately prior to the transaction.

If the conditions specified in our operating agreement are satisfied, our managing member may convert our company or any of our subsidiaries into a new limited liability entity or merge us or any of our subsidiaries into, or convey all of our assets to, a newly formed entity that has no assets, liabilities, or operations, if (i) the sole purpose of that conversion, merger, or conveyance is to effect a mere change in our legal form into another limited liability entity, (ii) we have received an opinion of counsel regarding limited liability matters, and (iii) our managing member determines that the governing instruments of the new entity provide the non-managing members and our managing member with substantially the same rights and obligations as contained in our operating agreement. Holders of ENLC Units will not be entitled to dissenters' rights of appraisal under our operating agreement or applicable Delaware law in the event of a conversion, merger, or consolidation, a sale of substantially all of our assets, or any other similar transaction or event.

Dissolution

We will continue as a limited liability company until dissolved under the terms of our operating agreement. We will dissolve upon:

- the election by our managing member to dissolve our business, if approved by a unit majority;
- there being no members other than our managing member, unless we are continued without dissolution in accordance with the DLLCA;
- the entry of a decree of judicial dissolution pursuant to the provisions of the DLLCA; or
- the withdrawal or removal of our managing member or any other event that results in its ceasing to be our managing member other than by reason of a transfer of its managing member interest in accordance with our operating agreement or its withdrawal or removal following the approval and admission of a successor.

Upon a dissolution under the last clause above, the holders of a unit majority may also elect, within specific time limitations, to continue our business on the same terms and conditions described in our operating agreement by appointing as a successor managing member an entity approved by a unit majority, subject to the receipt by us of an opinion of counsel to the effect that the action would not result in the loss of limited liability under Delaware law of any member.

Liquidation and Distribution of Proceeds

If we dissolve in accordance with our operating agreement, unless our business is continued, the liquidator authorized to wind up our affairs will, acting with all of the powers of our managing member that are necessary or appropriate, liquidate our assets. The liquidator will first apply the proceeds of liquidation to the payment of our creditors and, thereafter, holders of our common units would be entitled to share ratably in the distribution of any remaining proceeds.

Withdrawal or Removal of Our Managing Member

Our managing member may withdraw as managing member without first obtaining approval of our unitholders by giving 90 days' written notice, and that withdrawal will not constitute a violation of our operating agreement. In addition, our operating agreement permits our managing member, in some instances, to sell or otherwise transfer all of its managing member interest in us without the approval of the unitholders.

Upon withdrawal of our managing member under any circumstances, other than as a result of a transfer by our managing member of all or a part of its managing member interest in us, the holders of a unit majority may select a successor to that withdrawing managing member. If a successor is not elected, or is elected but an opinion of counsel regarding limited liability matters cannot be obtained, we will be dissolved, wound up, and liquidated, unless within a specified period after that withdrawal, the holders of a unit majority agree in writing to continue our business and to appoint a successor managing member. See "–Dissolution."

Our managing member may not be removed unless (i) that removal is approved by the vote of the holders of not less than $66\frac{2}{3}$ % of the outstanding ENLC Units, including ENLC Units held by our managing member and its affiliates, and (ii) we have received an opinion of counsel regarding limited liability matters. Any removal of our managing member is also subject to the approval of a successor managing member by the vote of a unit majority, including ENLC Units held by our managing member and its affiliates. The ownership of more than 33 $^{1}/_{3}$ % of the voting power of the ENLC Units by our managing member and its affiliates gives them the ability to prevent their removal as our managing member.

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

If the option described above is not exercised by either the departing managing member or the successor managing member, the departing managing member's managing member interest will automatically convert into common units equal to the fair market value of those interests as determined by an investment banking firm or other independent expert selected in the manner described in the preceding paragraph.

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

Transfer of Managing Member Interest

At any time, our managing member may transfer all or any part of its managing member interest in us to another person without the approval of any other member. As a condition of this transfer, the transferee must, among other things, assume the rights and duties of our managing member, agree to be bound by the provisions of our operating agreement, and furnish an opinion of counsel regarding limited liability matters.

Transfer of Ownership Interests in Our Managing Member

At any time, the owner of our managing member may sell or transfer all or part of its ownership interests in our managing member to an affiliate or third party without the approval of our unitholders.

Change of Management Provisions

Our operating agreement contains specific provisions that are intended to discourage a person or group from attempting to remove our managing member or from otherwise changing our management. If any person or group, other than our managing member and its affiliates, acquires beneficial ownership of 20% or more of any class of ENLC Units, that person or group loses voting rights on all of its ENLC Units. This loss of voting rights does not apply to any person or group that acquires the ENLC Units from our managing member or its affiliates and any transferees of that person or group approved by our managing member or to any person or group who acquires the common units with the prior approval of our board of directors.

Call Right

If at any time our managing member and its affiliates own more than 90% of the then-issued and outstanding membership interests of any class, our managing member will have the right, which it may assign in whole or in part to any of its affiliates or to our managing member, to acquire all, but not less than all, of the membership interests of the class held by unaffiliated persons, as of a record date to be selected by our managing member, on at least 10, but not more than 60, days' notice. The purchase price in the event of this purchase is the greater of:

- the highest price paid by our managing member or any of its affiliates for any membership interests of the class purchased within the 90 days preceding the date on which our managing member first mails notice of its election to purchase those membership interests; and

- the average of the daily closing prices of the membership interests of such class over the 20 trading days preceding the date that is three days before the date the notice is mailed.

As a result of our managing member's right to purchase outstanding membership interests, a holder of membership interests may have his membership interests purchased at an undesirable time or at a price that may be lower than market prices at various times prior to such purchase or lower than a unitholder may anticipate the market price to be in the future. The tax consequences to a holder of ENLC Units of the exercise of this call right are the same as a sale by that unitholder of its ENLC Units in the market.

Meetings; Voting

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

Any action that is required or permitted to be taken by the unitholders may be taken either at a meeting of the unitholders or, if authorized by the managing member, without a meeting if consents in writing describing the action so taken are signed by holders of the number of ENLC Units necessary to authorize or take that action at a meeting. Meetings of the unitholders may be called by our managing member or by unitholders owning at least 20% of the outstanding units of the class for which a meeting is proposed. Unitholders may vote either in person or by proxy at meetings. The holders of a majority of the outstanding units of the class or classes for which a meeting has been called, represented in person or by proxy, will constitute a quorum, unless any action by the unitholders requires approval by holders of a greater percentage of the units, in which case the quorum will be the greater percentage.

Each record holder of an ENLC Unit will have a vote according to such holder's percentage interest in us, although additional membership interests having special voting rights could be issued. See "–Issuance of Additional Interests." However, if at any time any person or group, other than our managing member and its affiliates, or a direct or subsequently approved transferee of our managing member or its affiliates and purchasers specifically approved by our managing member, acquires, in the aggregate, beneficial ownership of 20% or more of any class of units, that person or group will lose voting rights on all of its ENLC Units, and the ENLC Units may not be voted on any matter and will not be considered to be outstanding when sending notices of a meeting of unitholders, calculating required votes, determining the presence of a quorum or for other similar purposes. Our common units held in nominee or street name account will be voted by the broker or other nominee in accordance with the instruction of the beneficial owner unless the arrangement between the beneficial owner and his nominee provides otherwise.

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

Status as Member

By transfer of our common units in accordance with our operating agreement, each transferee of our common units shall be admitted as a member with respect to our common units transferred when such transfer and admission are reflected in our books and records. Except as described under "–Limited Liability," our common units will be fully paid, and unitholders will not be required to make additional contributions.

Indemnification

Section 18-108 of the DLLCA, as amended, empowers a Delaware limited liability company to indemnify and hold harmless any member or manager or other person from and against all claims and demands whatsoever. Our operating agreement provides that we will indemnify the following persons, to the fullest extent permitted by the law, from and against all losses, claims, damages, or similar events:

- our managing member;
- any departing managing member;
- any person who is or was an affiliate of our managing member or any departing managing member;
- any person who is or was one of our managers, managing members, general partners, directors, officers, employees, agents, fiduciaries or trustees, our subsidiaries, our managing member, any departing managing member, or any of their respective affiliates;
- any person who is or was serving as a manager, managing member, general partners, director, officer, employee, agent, fiduciary, or trustee of another person owing a fiduciary duty to us or our subsidiaries; and
- any person designated by our managing member;

unless there has been a final and non-appealable judgment by a court of competent jurisdiction that, in respect of the matter for which such persons are seeking indemnification, those persons acted in bad faith, or engaged in fraud or willful misconduct or, in the case of a criminal matter, acted with knowledge that their conduct was unlawful.

Any indemnification under these provisions will only be out of our assets. Unless our managing member otherwise agrees, it will not be personally liable for, or have any obligation to contribute or lend funds or assets to us to enable us to effectuate, indemnification. We may purchase insurance against liabilities asserted against and expenses incurred by persons for our activities, regardless of whether we would have the power to indemnify the person against liabilities under our operating agreement.

We have entered into indemnification agreements with each of the directors and executive officers of our managing member. Under the terms of these indemnification agreements, we agree to indemnify and hold each indemnitee harmless 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 and any and all "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 otherwise, whether made pursuant to federal, state, or local law, whether formal or informal, and including appeals, in each case, 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 or our managing member, or is or was serving at the request of us or our managing member, each as applicable, as a manager, managing member, general partner, director, officer, fiduciary, trustee, or agent of any other entity, organization, or person of any nature. We have also agreed to advance the expenses of an indemnitee relating to the foregoing. To the extent that a change in the laws of the State of Delaware permits greater indemnification under any statute, agreement, organizational document, or governing document than would be afforded under the indemnification agreements as of the date of the indemnification agreements, the indemnitee shall enjoy the greater benefits so afforded by such change.

Reimbursement of Expenses

Our operating agreement requires us to reimburse our managing member on a monthly basis for all direct and indirect expenses it incurs or payments it makes on our behalf and all other expenses allocable to us or otherwise incurred by our managing member in connection with operating our business. Our operating agreement does not set a limit on the amount of expenses for which our managing member and its affiliates may be reimbursed. These expenses include salary, bonus, incentive compensation, and other amounts paid to persons who perform services for us or on our behalf and expenses allocated to our managing member by its affiliates. Our managing member is entitled to determine the expenses that are allocable to us.

Books and Reports

Our managing member is required to keep appropriate books of our business at its principal offices. These books will be maintained for both tax and financial reporting purposes on an accrual basis in accordance with generally acceptable accounting principles (GAAP). For tax and fiscal reporting purposes, our fiscal year is the calendar year.

We will furnish or make available to record holders of our common units, within 105 days after the close of each fiscal year, an annual report containing audited consolidated financial statements and a report on those consolidated financial statements by its independent public accountants. Except for its fourth quarter, we will also furnish or make available summary financial information within 50 days after the close of each quarter. We will be deemed to have made any such report available if we file such report with the SEC via its Electronic Data Gathering, Analysis and Retrieval system or make the report available on a publicly available website which we maintain.

Right to Inspect Books and Records

Our operating agreement provides that a member can, for a purpose reasonably related to such member's interest as a member, upon reasonable written demand stating the purpose of such demand and at such member's own expense, have furnished to such member:

- true and full information regarding the status of our business and financial condition (provided that this obligation shall be satisfied to the extent the member is furnished the most recent annual report and any subsequent quarterly or periodic reports required to be filed (or which would be required to be filed) with the SEC by us pursuant to Section 13 of the Exchange Act); and

- a current list of the name and last known address of each record holder; and copies of our operating agreement, our certificate of formation, related amendments, and powers of attorney under which they have been executed.

Under our operating agreement, however, each of our members and other persons who acquire our membership interests, do not have rights to receive information from us or any of the persons we indemnify as described above under "–Indemnification" for the purpose of determining whether to pursue litigation or assist in pending litigation against us or those indemnified persons relating to its affairs, except pursuant to the applicable rules of discovery relating to the litigation commenced by the person seeking information.

Our managing member may, and intends to, keep confidential from our members trade secrets or other information the disclosure of which our managing member determines is not in our best interests, could damage us or that we are required by law or by agreements with third parties to keep confidential. Our operating agreement limits the right to information that a member would otherwise have under Delaware law.

Conflicts of Interest

Conflicts of interest exist and may arise in the future as a result of the relationships between our managing member or its affiliates, on the one hand, and us, our members, or our subsidiaries, on the other hand. Our operating agreement specifically defines the remedies available to our unitholders for actions taken that, without these defined liability standards, might constitute breaches of fiduciary duty under applicable Delaware law. The DLLCA provides that Delaware limited liability companies may, in their operating agreements, expand, restrict, or eliminate the fiduciary duties otherwise owed by the manager to the members and the company, but such agreements may not eliminate the implied contractual covenant of good faith and fair dealing.

Whenever a conflict arises between our managing member or its affiliates, on the one hand, and us, our members, or our subsidiaries, on the other hand, the resolution or course of action in respect of such conflict of interest shall be permitted and conclusively deemed approved by us and all of our members and shall not constitute a breach of our operating agreement, of any agreement contemplated thereby, or of any duty, if the resolution or course of action in respect of such conflict of interest is:

- approved by the conflicts committee of our board of directors; or
- approved by a unit majority, excluding any such common units owned by our managing member and its affiliates.

Our managing member may, but is not required to, seek the approval of such resolutions or courses of action from the conflicts committee of our board of directors or from the holders of a majority of the outstanding common units as described above. Unless the resolution of a conflict is specifically provided for in our operating agreement, our board of directors or the conflicts committee of our board of directors may consider any factors they determine in good faith to consider when resolving a conflict. An independent third party is not required to evaluate the resolution. Under our operating agreement, a determination, other action, or failure to act by our managing member, our board of directors, or any committee thereof (including the conflicts committee) will be deemed to be in “good faith” if our managing member, our board of directors, or any committee thereof (including the conflicts committee) subjectively believed such determination, other action or failure to act was in, or not opposed to, our best interests. In any proceeding brought by or on behalf of us or any of our unitholders, the person bringing or prosecuting such proceeding will have the burden of proving that such determination, other action, or failure to act was not in good faith.

Elimination and Replacement of Fiduciary Duties

Duties owed to unitholders by our managing member are prescribed by law and in our operating agreement. The DLLCA provides that Delaware limited liability companies may, in their operating agreements, expand, restrict, or eliminate the fiduciary duties otherwise owed by our managing member to members and us.

Our operating agreement contains various provisions that eliminate and replace the fiduciary duties that might otherwise be owed by our managing member. These provisions have been negotiated to allow our managing member or its affiliates to engage in transactions with us that otherwise might be prohibited by state law fiduciary standards and to take into account the interests of other parties in addition to our interests when resolving conflicts of interest. Without these modifications, our managing member’s ability to make decisions involving conflicts of interest would be restricted. Replacing the fiduciary duty standards in this manner benefits our managing member by enabling it to take into consideration all parties involved in the proposed action. Replacing the fiduciary duty standards also strengthens the ability of our managing member to attract and retain experienced and capable directors. Replacing the fiduciary duty standards represents a detriment to our public unitholders because it restricts the remedies available to the public unitholders for actions that, without those limitations, might constitute breaches of fiduciary duty, as described below, and permits our managing member to take into account the interests of third parties in addition to our interests when resolving conflicts of interests.

The following is a summary of the fiduciary duties imposed on managers of a limited liability company by the DLLCA in the absence of operating agreement provisions to the contrary, the contractual duties of our managing member contained in our operating agreement that replace the fiduciary duties that would otherwise be imposed by

Delaware laws on our managing member and the rights and remedies of its unitholders with respect to these contractual duties:

State law fiduciary standards	Fiduciary duties are generally considered to include an obligation to act in good faith and with due care and loyalty. The duty of care, in the absence of a provision in an operating agreement providing otherwise, would generally require a managing member to act for the company in the same manner as a prudent person would act on his own behalf. The duty of loyalty, in the absence of a provision in an operating agreement providing otherwise, would generally require that any action taken or transaction engaged in be entirely fair to the company.
Operating agreement modified standards	Our operating agreement contains provisions that waive or consent to conduct by our managing member and its affiliates that might otherwise raise issues as to compliance with fiduciary duties or applicable law. For example, our operating agreement provides that when our managing member is acting in its capacity as our managing member, as opposed to in its individual capacity, it must act in "good faith" and will not be subject to any other standard under applicable law (other than the implied contractual covenant of good faith and fair dealing). In addition, when our managing member is acting in its individual capacity, as opposed to in its capacity as our managing member, it may act without any fiduciary obligation to us or the unitholders whatsoever. These standards replace the obligations that our managing member would otherwise be held to. If our managing member does not obtain approval from the conflicts committee of the board of directors of our managing member or the holders of our common units, excluding any units owned by our managing member or its affiliates, and our board of directors approves the resolution or course of action taken with respect to the conflict of interest, then it will be presumed that, in making its decision, our board of directors, which may include board members affected by the conflict of interest, acted in good faith, and in any proceeding brought by or on behalf of any member or us, the person bringing or prosecuting such proceeding will have the burden of overcoming such presumption. These standards replace the obligations that our managing member would otherwise be held to.
Rights and remedies of unitholders	The DLLCA generally provides that a member may institute legal action on behalf of the company to recover damages from a third party where a manager has refused to institute the action or where an effort to cause a manager to do so is not likely to succeed. These actions include actions against a manager for breach of its duties or of our operating agreement. In addition, the statutory or case law of some jurisdictions may permit a member to institute legal action on behalf of himself and all other similarly situated members to recover damages from a manager for violations of its fiduciary duties to the members.
Operating agreement modified standards	The DLLCA provides that, unless otherwise provided in an operating agreement, a member or other person shall not be liable to a limited liability company or to another member or to another person that is a party to or is otherwise bound by an operating agreement for breach of fiduciary duty for the member's or other person's good faith reliance on the provisions of the operating agreement. Under our operating agreement, to the extent that, at law or in equity an indemnitee has duties (including fiduciary duties) and liabilities relating thereto to us or to our members, our managing member, and any other indemnitee acting in connection with its business or affairs shall not be liable to us or to any member for its good faith reliance on the provisions of our operating agreement.

By acquiring our common units, each new holder of our common units automatically agrees to be bound by the provisions in our operating agreement, including the provisions discussed above. This is in accordance with the policy of the DLLCA favoring the principle of freedom of contract and the enforceability of operating agreements. The failure of a member to sign an operating agreement does not render the operating agreement unenforceable against that person.

Under our operating agreement, we must indemnify our managing member and its officers, directors, managers, and certain other specified persons, to the fullest extent permitted by law, against liabilities, costs, and expenses incurred by our managing member or these other persons. We must provide this indemnification unless there has been a final and non-appealable judgment by a court of competent jurisdiction determining that these persons acted in bad faith, or engaged in fraud or willful misconduct. We must also provide this indemnification for criminal proceedings unless our managing member or these other persons acted with knowledge that their conduct was unlawful. Thus, our managing member could be indemnified for its negligent acts if it meets the requirements set forth above. To the extent these provisions purport to include indemnification for liabilities arising under the Securities Act in the opinion of the SEC, such indemnification is contrary to public policy and, therefore, unenforceable. See "–Indemnification."

CASH DISTRIBUTION POLICY

Our Cash Distribution Policy

We make cash distributions, if any, to holders of our common units on a pro rata basis; provided, however, that, if ENLK fails to pay in full certain cash amounts with respect to quarterly distributions to the holder of the ENLK Series B Units when due, then from and after the first date of such failure and continuing until such failure is cured by payment in full in cash of all such cash arrearages, we are not permitted to, and will not, declare or make any distributions in respect of our common units and any other class of membership interests that, with respect to distributions, ranks junior to the ENLK Series B Units.
Unless restricted by the terms of the agreements governing our outstanding indebtedness, we intend to pay distributions to holders of our common units on a quarterly basis from our available cash less reserves for expenses, future distributions, and other uses of cash, including:

- provisions for the proper conduct of our business;
- paying federal income taxes, which we are required to pay because we are taxed as a corporation; and
- maintaining cash reserves the board of directors of our managing member believes are prudent to maintain.

Our ability to pay distributions is limited by the DLLCA, which provides that a limited liability company may not pay distributions if, after giving effect to the distribution, the company's liabilities would exceed the fair value of its assets. While our ownership of equity interests in ENLK are included in our calculation of net assets, the value of these assets may decline to a level where our liabilities would exceed the fair value of our assets if we were to pay distributions, thus prohibiting us from paying distributions under Delaware law.

DESCRIPTION OF NOTES

We are party to a base indenture, dated as of April 9, 2019, between us and Wells Fargo Bank, National Association, as trustee, pursuant to which we issued the notes, as supplemented by a supplemental indenture among us, ENLK, as guarantor, and Wells Fargo Bank, National Association, as trustee, setting forth the specific terms of the notes. In this description, when we refer to the "indenture," we mean the base indenture as so amended and supplemented by the 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. The following summary of the indenture and the notes does not purport to be complete and is qualified in its entirety by reference to the full text of the base indenture and the supplemental indenture, copies of which are filed as Exhibits 4.1 and 4.2, respectively, to ENLC's Current Report on Form 8-K dated April 4, 2019, filed with the SEC on April 9, 2019, file No. 001-36336.

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

General

The notes:

- are general unsecured, senior obligations of ENLC, ranking equally with all other existing and future unsecured and unsubordinated indebtedness of ENLC;
- were issued in an aggregate principal amount of $500 million;
- will mature on June 1, 2029;
- were issued in denominations of $2,000 and integral multiples of $1,000 in excess thereof;
- bear interest at an annual rate of 5.375%; and
- are redeemable at any time at our option at the applicable redemption price described below under "–Optional Redemption."

The notes constitute a 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

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

Interest 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 the issue date, public offering 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

Prior to March 1, 2029 (three months prior to the maturity date of the notes) (the "Par Call Date"), the 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 notes to be redeemed that would be due if the notes matured on the Par Call Date (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 the Par Call Date, the 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 notes to be redeemed plus accrued and unpaid interest thereon to, but excluding, the redemption date.

For purposes of determining the redemption price, 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 notes to be redeemed (calculated as if the maturity date of the notes was the Par Call Date) 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 notes (calculated as if the maturity date of the notes was the Par Call Date).

"*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.

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

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

"*Reference Treasury Dealer*" means each of (i) RBC Capital Markets, LLC, BMO Capital Markets Corp., and Wells Fargo Securities, LLC and their respective successors that are Primary Treasury Dealers and (ii) a Primary Treasury Dealer selected by SunTrust Robinson Humphrey, Inc. or it successor, provided that, if at any time any of the foregoing is not a Primary Treasury Dealer, ENLC will substitute therefor another Primary Treasury Dealer.

"*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 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 15 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.

Subsidiary Guarantees

The notes are guaranteed by our subsidiary, ENLK. None of our other Subsidiaries guaranteed the notes upon their issuance. However, if at any time following the issuance of the notes, any other Subsidiary of ENLC becomes a guarantor or co-obligor of the Credit Agreement or the Term Loan, then ENLC will cause such Subsidiary to promptly execute and deliver to the trustee a supplemental indenture in a form satisfactory to the trustee pursuant to which such Subsidiary guarantees ENLC's obligations with respect to the notes on the terms provided for in the indenture.

The guarantee of ENLK and any other Subsidiary Guarantor may be released under certain circumstances. If we exercise our legal or covenant defeasance option with respect to the notes as described below under "–Defeasance and Discharge," then ENLK and any other Subsidiary Guarantor will be released. Further, if no default has occurred and is continuing under the indenture, and to the extent not otherwise prohibited by the indenture, any Subsidiary Guarantor will be unconditionally released and discharged from its guarantee:

- automatically upon any sale, exchange, or transfer, whether by way of merger or otherwise, to any Person that is not our affiliate, of all of the direct or indirect limited partnership interests or other equity interests in the Subsidiary Guarantor;

- automatically upon the merger of the Subsidiary Guarantor into us or any other Subsidiary Guarantor or the liquidation and dissolution of the Subsidiary Guarantor; or

- following delivery of a written notice by us to the trustee, upon the release of all guarantees or other obligations of the Subsidiary Guarantor with respect to the obligations of ENLC or any of its Subsidiaries under the Credit Agreement and the Term Loan.

If at any time following any release of ENLK or any other Subsidiary Guarantor from its guarantee of the notes pursuant to the third bullet point in the preceding paragraph, the Subsidiary Guarantor again becomes a guarantor or co-obligor of the Credit Agreement or the Term Loan, then ENLC will cause the Subsidiary Guarantor to again guarantee the notes in accordance with the indenture.

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 ENLC and rank equally with all other existing and future unsubordinated indebtedness of ENLC. The guarantee of the notes by ENLK and any guarantee of the notes by any other Subsidiary Guarantor is an unsecured and unsubordinated obligation of ENLK or the applicable Subsidiary Guarantor and rank equally with all other existing and future unsubordinated indebtedness of ENLK (including its outstanding senior notes and its guarantee of the Credit Agreement and the Term Loan) and the applicable Subsidiary Guarantor. The notes and each guarantee will effectively rank junior to any future indebtedness of ENLC or any Subsidiary Guarantor that is both secured and unsubordinated to the extent of the value of the assets securing such indebtedness, and the notes structurally rank junior to all indebtedness and other liabilities of ENLC's existing and future Subsidiaries that are not Subsidiary Guarantors.

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 ENLC 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 limited liability company or other equity interests or from purchasing or redeeming its limited liability company 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 ENLC to repurchase or redeem or otherwise modify the terms of the notes upon a change in control or other events involving ENLC that could adversely affect the creditworthiness of ENLC.

Limitations on Liens. ENLC 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 ENLC 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, ENLC 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 ENLC 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 ENLC 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 ENLC or any of its Subsidiaries on the date of the supplemental indenture creating the notes, in each case owned by a Subsidiary of ENLC (an "Excluded Subsidiary") that (A) is not, and is not required to be, a Subsidiary Guarantor and (B) has not granted any liens on any of its property securing Indebtedness with recourse to ENLC or any Subsidiary of ENLC other than such Excluded Subsidiary or any other Excluded Subsidiary.

Restriction on Sale-Leasebacks. ENLC will not, and will not permit any Principal Subsidiary to, engage in the sale or transfer by ENLC or any of its Principal Subsidiaries of any Principal Property to a Person (other than ENLC or a Principal Subsidiary) and the taking back by ENLC 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. ENLC 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. ENLC 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 ENLC 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 ENLC or its Subsidiaries.

Notwithstanding the foregoing, ENLC 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 permitted by clause (b) of the second paragraph of the restriction on liens covenant described above, does not exceed 15% of Consolidated Net Tangible Assets.

Merger, Consolidation or Sale of Assets. ENLC 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 ENLC or expressly assumes by supplemental indenture all of ENLC'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 or Event of Default has occurred and is continuing;

4. if ENLC is not the successor, then each Subsidiary Guarantor confirms to the Trustee that the guarantee of such Subsidiary Guarantor continues to apply; and

5. ENLC 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 ENLC 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 ENLC under the indenture. If ENLC 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 the notes issued thereunder, when:

(a) either:
    (1) all outstanding notes 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

    (2) all outstanding notes 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 the notes not delivered to the Trustee for cancellation, for principal, premium, if any, and accrued interest to the stated maturity or redemption date;

(b) we have paid or caused to be paid all other sums payable by us under the indenture with respect to the notes; and

(c) 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 the 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 the notes in certain circumstances, and to transfer or exchange the notes 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 the notes, all our obligations under the 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 the notes, which covenants are described in the prospectus supplement applicable to the notes, 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 debt securities 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:

- failure by us or by a guarantor to comply for 60 days after notice with the other agreements contained in the indenture, any supplement to the indenture with respect to the notes or any board resolution authorizing the issuance of the notes;
- certain events of bankruptcy, insolvency, or reorganization of us or, if the series of debt securities is guaranteed by the guarantors, of the guarantors; or
- (i) any of the guarantees by the guarantors ceases to be in full force and effect, except as otherwise provided in the indenture; (ii) any of the guarantees by the guarantors is declared null and void in a judicial proceeding; or (iii) any guarantor denies or disaffirms its obligations under the indenture or its guarantee.
- 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 person 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 security or indemnity satisfactory to it 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 ENLC and its Subsidiaries.

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.

The notes are 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 affect 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 will be 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. Neither ENLC, 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 is similarly required to make book-entry transfers and to receive and transmit payments with respect to the notes. ENLC, 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. ENLC, 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. ENLC also does not supervise these systems in any way.

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.

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 us 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 ENLC 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 ENLC and its consolidated Subsidiaries for ENLC's most recently completed fiscal quarter for which financial statements have been filed with the SEC, prepared in accordance with generally accepted accounting principles.

"*Credit Agreement*" means the Revolving Credit Agreement, dated as of December 11, 2018, among ENLC, Bank of America, N.A., as Administrative Agent, and the other agents and lenders party thereto, as amended, restated, or otherwise modified from time to time, and any successor or replacement agreement with banks or other financial institutions that provides for revolving loans to ENLC or ENLK.

"*Exchange Act*" means the Securities Exchange Act of 1934, as amended, and any successor statute.

"*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.

"*Managing Member*" means EnLink Midstream Manager, LLC, a Delaware limited liability company, and its successors as managing member of ENLC.

"*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 ENLC 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 ENLC or any Subsidiary or the use thereof or the rights and interests of ENLC or any Subsidiary therein, in any manner under any and all laws;

4. rights reserved to the grantors of any properties of ENLC 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 ENLC 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 ENLC 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 ENLC or any Subsidiary;

11. any lien upon any property or assets of ENLC 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 or 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, surety, stay, customs, and appeal bonds, performance and return-of money bonds, bankers' acceptance facilities, 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 ENLC 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 ENLC 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 ENLC 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 ENLC 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 ENLC 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 ENLC 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 ENLC 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 ENLC 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):

    - 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

    - any such assets which, in the opinion of the board of directors of the Managing Member are not material in relation to the activities of ENLC 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) a partnership (whether general or limited) in which such Person or a Subsidiary of such Person is, at the date of determination, a general partner of such partnership, but only if such Person, directly or by one or more Subsidiaries of such Person, or a combination thereof, controls such partnership on the date of determination, or (3) any other Person in which such Person, one or more Subsidiaries of such Person, or a combination thereof, directly or indirectly, at the date of determination, has (i) a majority ownership interest or (ii) the power to elect or direct the election of directors with a majority of the voting power of the board of directors (or other governing body) of such Person or the sole member or managing member of such Person, as applicable.

"*Subsidiary Guarantor*" means each Subsidiary of ENLC that guarantees the notes pursuant to the terms of the indenture but only so long as such Subsidiary is a guarantor with respect to the notes on the terms provided for in the indenture.

"*Term Loan*" means the Term Loan Agreement, dated as of December 11, 2018, among ENLK, Bank of America, N.A., as Administrative Agent, the other agents and lenders party thereto, and pursuant to the New Borrower Joinder and Assumption Agreement, dated as of January 25, 2019, ENLC, and as further amended, restated, or supplemented from time to time, and any successor or replacement agreement with banks or other financial institutions that provides for one or more term loans to ENLC or ENLK.

PERFORMANCE UNIT AGREEMENT

THIS PERFORMANCE UNIT AGREEMENT (this "***Agreement***") is entered into by and between EnLink Midstream, LLC, a Delaware limited liability company (the "***Company***"), and _____________ ("***Participant***") as of the Grant Date (as defined below).

WITNESSETH:

WHEREAS, the EnLink Midstream, LLC 2014 Long-Term Incentive Plan was adopted by the Company, effective February 5, 2014 (as amended, the "***Plan***"), for the benefit of certain employees and consultants of the Company or its Affiliates (as defined in the Plan), and non-employee directors of EnLink Manager (as defined in the Plan), the managing member of the Company; and

WHEREAS, the Committee (as defined in the Plan) is responsible for granting Awards (as defined in the Plan) in accordance with the Plan; and

WHEREAS, Participant is eligible to participate in the Plan and the Committee has authorized the grant to Participant of the "***Subject Award***" (as defined in Section 2 of this Agreement), which shall be subject to certain restrictions pursuant to the Plan and upon the terms set forth herein.

NOW, THEREFORE, in consideration of the premises and the mutual covenants and agreements hereinafter set forth, the Company and Participant hereby agree as follows:

1. Definitions. Capitalized terms used herein and not otherwise defined herein shall have the meaning ascribed to them in the Plan.

"***Cause***" shall have the meaning ascribed to such term (i) in the Severance Agreement (which meaning shall include any procedural aspects for establishing a termination for Cause pursuant to the Severance Agreement), or (ii) in the Plan if no Severance Agreement exists.

"***CF Tranche RIUs***" means the Tranche RIUs with a Performance Goal based on Cash Flow.

"***Change in Control***" shall have the meaning ascribed to such term (i) in the Change in Control Agreement (which meaning shall include any procedural aspects for establishing a termination for Change in Control pursuant to the Change in Control Agreement), or (ii) in the Plan if no Change in Control Agreement exists.

"***Change in Control Agreement***" means (i) the Change in Control Agreement, as amended, if any, between Participant and EnLink Midstream Operating, LP, a Delaware limited partnership (or its successor), that is in effect as of the Grant Date or (ii) if Participant is not a party to a Change in Control Agreement contemplated in clause (i) of this definition, the most recent form of change in control agreement that has been included as an exhibit to the Company's filings with the U.S. Securities and Exchange Commission (the "***SEC***") prior to the Grant Date.

"***Company Group***" means the Company, EnLink Midstream Manager, LLC, EnLink Midstream Partners, LP, EnLink Midstream GP, LLC, EnLink Midstream Operating, LP and each of their respective direct or indirect subsidiaries.

"***Early Retirement***" means (i) Participant's Retirement on or after his or her attainment of age 55, and (ii) immediately prior to such Retirement, the number of such Participant's years of continuous service with the Company or its Affiliates (including continuous service with a predecessor employer that is taken into account pursuant to an acquisition or other transaction agreement) equals or exceeds 10 years. For the avoidance of doubt, a Normal Retirement shall be deemed to occur, if at all, to the extent Participant meets the applicable age and service requirements to be eligible for both Early Retirement and Normal Retirement.

"***End Date***" means the date on which the Cumulative Performance Period ends.

“***Good Reason***” (i) shall have the meaning ascribed to such term in the Severance Agreement (which meaning shall include any procedural aspects for establishing a termination for Good Reason pursuant to the Severance Agreement), or, (ii) if no Severance Agreement exists, then shall mean any of the following, without Participant’s consent: (w) a material reduction in Participant’s base annual salary; (x) a material adverse change in Participant’s authority, duties, or responsibilities (other than temporarily while Participant is physically or mentally incapacitated or as required by applicable law); (y) a material breach by the Company of any material provision of this Agreement (or by a member of the Company Group of any material provision of any other written agreement between Participant and any member of the Company regarding his or her services thereto); or (z) the Company requires that Participant move his or her principal place of service to a location that is thirty (30) or more miles from his or her current principal place of service and the new location is farther from his or her primary residence. Participant may not terminate his or her employment for “Good Reason” unless (A) Participant gives the Company written notice of the event within thirty (30) days of the occurrence of the event, (B) the Company fails to remedy the event within thirty (30) days following its receipt of the notice, and (C) Participant terminates his or her service with the Company and its Affiliates within sixty (60) days following the Company’s receipt of written notice.

“***Grant Date***” means [●].

“***Intermediate Retirement***” means (i) Participant’s Retirement on or after his or her attainment of age 60, and (ii) immediately prior to such Retirement, the number of such Participant’s years of continuous service with the Company or its Affiliates (including continuous service with a predecessor employer that is taken into account pursuant to an acquisition or other transaction agreement) is less than five years.

“***Normal Retirement***” means (i) Participant’s Retirement on or after his or her attainment of age 60, and (ii) immediately prior to such Retirement, the number of such Participant’s years of continuous service with the Company or its Affiliates (including continuous service with a predecessor employer that is taken into account pursuant to an acquisition or other transaction agreement) equals or exceeds five years; *provided*, *however,* that, a Normal Retirement will not occur if Participant’s Retirement occurs prior to the one-year anniversary of the commencement of the First Performance Period unless the Committee approves the same in its sole discretion. For the avoidance of doubt, a Normal Retirement shall be deemed to occur, if at all, to the extent Participant meets the applicable age and service requirements to be eligible for both Early Retirement and Normal Retirement.

“***Performance Goal***” means, with respect to a Subject Tranche, the applicable Performance Goal as set forth in Schedule B to this Agreement.

“***Performance Period***” means the applicable measurement period under this Agreement for purposes of determining attainment of the Performance Goal with respect to a Subject Tranche.

Under this Agreement, the following four Performance Periods shall apply to the Performance Goal based on TSR:

- The “***First Performance Period***” shall comprise the period commencing on January 1, [●] and ending on December 31st of that same year;
- The “***Second Performance Period***” shall comprise the period commencing on January 1, [●] and ending on December 31st of that same year;
- The “***Third Performance Period***” shall comprise the period commencing on January 31, [●] and ending on December 31st of that same year; and
- The “***Cumulative Performance Period***” shall comprise the period commencing on January 1, [●] and ending on December 31, [●].

Under this Agreement, the following three Performance Periods shall apply to the Performance Goal based on Cash Flow:

- The First Performance Period;
- The Second Performance Period; and
- The Third Performance Period.

"***Prorated Amount***" means a number equal to the total number of Certified RIUs multiplied by a fraction (i) the numerator of which is the number of days that elapse from the commencement of the Cumulative Performance Period to, as applicable, the date of a Qualifying Termination or the date of an Early Retirement or an Intermediate Retirement, and (ii) the denominator of which is the total number of days in the Cumulative Performance Period.

"***Qualifying Disability***" means, as applicable, the earliest to occur of: (i) Participant's "disability" within the meaning of Treas. Reg. Section 1.409A-3(i)(4), or (ii) Participant's Separation from Service that is incurred after Participant has become disabled and qualified to receive benefits under the Company's long-term disability plan.

"***Qualifying Termination***" means Participant's Separation from Service with the Company and its Affiliates due to (i) an involuntary termination of Participant by the Company or its Affiliates for reasons other than Cause or Qualifying Disability or (ii) a termination by Participant for Good Reason.

"***Retirement***" means Participant's Separation from Service with the Company and its Affiliates for reasons other than Cause due to his or her retirement; *provided* that (i) Participant provides the Company with at least 90 days' advance written notice of such retirement, which notice may be waived by the Chief Executive Officer of EnLink Manager and (ii) such retirement is otherwise approved by the Chief Executive Officer of EnLink Manager in his or her sole discretion. Notwithstanding any provision herein to the contrary, Participant will not be eligible to receive any benefits hereunder with respect to Early Retirement or Intermediate Retirement, if such Participant is eligible to receive benefits with respect to Normal Retirement under any other Award.

"***Retirement Conditions***" means, with respect to Participant's Retirement, (i) Participant's compliance with Schedule D through the date of his or her Retirement and (ii) solely if requested by the Company in its sole discretion, Participant shall deliver to the Company, prior to his or her Retirement, an acknowledgment of his or her obligations to comply with Schedule D (it being understood that Participant agrees to the terms and conditions set forth in Schedule D if he or she engages in Early Retirement, Intermediate Retirement, or Normal Retirement regardless of whether he or she delivers any such acknowledgment).

"***Separation from Service***" shall have the meaning ascribed to such term in the guidance issued under Section 409A of the Code.

"***Severance Agreement***" means (i) the Severance Agreement, as amended, if any, between Participant and EnLink Midstream Operating, LP, a Delaware limited partnership (or its successor), that is in effect as of the Grant Date or (ii) if Participant is not a party to a Severance Agreement contemplated in clause (i) of this definition, the most recent form of severance agreement that has been included as an exhibit to the Company's filings with the SEC prior to the Grant Date.

"***Subject Tranche***" means, as further specified in Schedule A, the portion of the Subject Award (i.e., a designated number of Restricted Incentive Units) that relates to a particular Performance Period and particular Performance Goal.

"***Tranche RIUs***" means the Restricted Incentive Units that comprise a Subject Tranche.

"***Tranche Valuation Date***" means, with respect to a Subject Tranche, the last day of the Performance Period applicable to the Subject Tranche.

"***TSR Tranche RIUs***" means the Tranche RIUs with a Performance Goal based on TSR.

2 . Performance Unit Award. On the terms and conditions and subject to the restrictions, including forfeiture, hereinafter set forth, the Company hereby grants to Participant, and Participant hereby accepts, an award of [●] Restricted Incentive Units (the "***Subject Award***"). The Restricted Incentive Units granted hereunder shall be evidenced by the Committee in a book entry or in such other manner as the Committee may determine.

3. Vesting; Forfeiture.

(a) In General. The number of Tranche RIUs, if any, that are eligible for vesting as Certified RIUs hereunder shall be based on the Committee's determination of attainment and associated certification of the applicable Performance Goal, in each case, made in accordance with this Section 3, Schedule B, and Section 4 below. The Committee shall make Performance Goal attainment and certification determinations separately with respect to each Subject Tranche. If at least a "Threshold" performance level ("***Qualifying Performance***") is attained and certified, then the applicable number of Tranche RIUs determined under Schedule B and Section 4 below (the "***Certified RIUs***") shall vest and Units applicable to such Certified RIUs shall be paid out to Participant in accordance with Section 4 below so long as Participant remains in the continuous service of the Company or its Affiliates until the earlier of (i) the End Date or (ii) the date on which the earliest event occurs in accordance with and pursuant to Section 3(c) or Section 3(d) below whereby the relevant Certified RIUs or Tranche RIUs vest or expressly remain eligible for vesting. For the avoidance of doubt: (x) if a "Below Threshold" performance level is attained and certified, then no Certified RIUs shall relate to the Tranche RIUs and all such Tranche RIUs shall be forfeited; (y) if at least Qualifying Performance is attained and certified, but such performance does not equal or exceed the "Target" performance level pursuant to Schedule B, then the number of Tranche RIUs that exceeds the applicable number of the Certified RIUs shall be forfeited; and (z) if at least Qualifying Performance is attained and certified, but the Certified RIUs are adjusted for the Prorated Amount pursuant to Section 3(c) below, then the number of Tranche RIUs, if any, that exceeds the applicable number of the Certified RIUs, as adjusted for the Prorated Amount, shall be forfeited. All forfeitures under this Agreement shall be at no cost to the Company or Participant.

(b) Separation from Service in General. Except as otherwise provided in Section 3(c) below, if Participant experiences a Separation from Service with the Company and its Affiliates prior to the End Date, then he or she will forfeit the Subject Award.

(c) Special Vesting/Forfeiture Conditions. Tranche RIUs and Certified RIUs, if any, shall be subject to the following vesting and forfeiture conditions, which shall apply in connection with a Qualifying Termination, Retirement, Change in Control, Participant's death, or Qualifying Disability that occurs at a time when there are no grounds in existence for the involuntary termination of Participant (in good faith) by the Company or its Affiliates for Cause:

(i) General. Except as otherwise provided in this Section 3(c), if a Qualifying Termination, an Early Retirement, an Intermediate Retirement, or a Normal Retirement occurs while the Subject Award is outstanding, then the Tranche RIUs or Certified RIUs, if any, as applicable, shall remain eligible for vesting or vest, if at all, pursuant to clause (x), (y), or (z) below and subclauses (1) or (2) thereunder as follows:

(x) Qualifying Termination:

(1) If such a Qualifying Termination occurs on or after a given Tranche Valuation Date for which Qualifying Performance is attained and certified, then such Certified RIUs shall vest (without adjustment for the Prorated Amount) as of the date of such Qualifying Termination.

(2) If such a Qualifying Termination occurs prior to a given Tranche Valuation Date, then the applicable Tranche RIUs shall remain eligible for vesting, subject to the attainment and certification of Qualifying Performance and any Certified RIUs relating to such Tranche RIUs shall be adjusted for the Prorated Amount.

(y) Early Retirement or Intermediate Retirement:

(1) If such an Early Retirement or Intermediate Retirement occurs on or after a given Tranche Valuation Date for which Qualifying Performance is attained and certified, then, subject to Participant satisfying the Retirement Conditions, such Certified RIUs shall vest (without adjustment for the Prorated Amount) as of the date of such Early Retirement or Intermediate Retirement, as applicable.

(2) If such an Early Retirement or Intermediate Retirement occurs prior to a given Tranche Valuation Date, then, subject to Participant satisfying the Retirement Conditions, the applicable Tranche RIUs shall remain eligible for vesting, subject to the attainment and certification of Qualifying Performance and any Certified RIUs relating to such Tranche RIUs shall be adjusted for the Prorated Amount.

(z) Normal Retirement:

(1) If such a Normal Retirement occurs on or after a given Tranche Valuation Date for which Qualifying Performance is attained and certified, then, subject to Participant satisfying the Retirement Conditions, such Certified RIUs shall vest (without adjustment for the Prorated Amount) as of the date of such Normal Retirement.

(2) If such a Normal Retirement occurs prior to a given Tranche Valuation Date, then, subject to Participant satisfying the Retirement Conditions, such Tranche RIUs shall remain eligible for vesting, subject to the attainment and certification of Qualifying Performance (without adjustment for the Prorated Amount).

(ii) <u>Double Trigger - Advance/Concurrent Change in Control</u>. If a Change in Control occurs while the Subject Award is outstanding and, on or after such Change in Control, a Qualifying Termination, an Early Retirement, an Intermediate Retirement, or a Normal Retirement occurs during a Performance Period, then the Tranche RIUs or Certified RIUs, if any, as applicable, shall remain eligible for vesting or vest, if at all, pursuant to clause (x) or (y) as follows:

(x) Qualifying Termination: If such a Qualifying Termination occurs prior to a given Tranche Valuation Date, then (A) the relevant TSR Tranche RIUs shall remain eligible for vesting subject to the attainment and certification of Qualifying Performance (without adjustment for the Prorated Amount) and (B) the relevant CF Tranche RIUs shall be deemed to vest as Certified RIUs at the "Target" performance level (without adjustment for the Prorated Amount) as of the date of such Qualifying Termination. For the avoidance of doubt, such a Qualifying Termination that occurs on or after a given Tranche Valuation Date is addressed in Section 3(c)(i)(x)(1) above or Section 3(d) below, as applicable.

(y) Early Retirement, Intermediate Retirement, or Normal Retirement: If such an Early Retirement, an Intermediate Retirement, or a Normal Retirement occurs prior to a given Tranche Valuation Date, then, subject to Participant satisfying the Retirement Conditions, (A) the relevant TSR Tranche RIUs shall remain eligible for vesting subject to the attainment and certification of Qualifying Performance (without adjustment for the Prorated Amount) and (B) the relevant CF Tranche RIUs shall be deemed to vest as Certified RIUs at the "Target" performance level (without adjustment for the Prorated Amount) as of the date of such Early Retirement, Intermediate Retirement, or Normal Retirement, as applicable. For the avoidance of doubt, each of such an Early Retirement, an Intermediate Retirement, or a Normal Retirement that occurs on or after a given Tranche Valuation Date is addressed in Section 3(c)(i)(y)(1) above, 3(c)(i)(z)(1) above, or Section 3(d) below, as applicable.

(iii) <u>Double Trigger – Subsequent Change in Control</u>. If, subsequent to the occurrence of a Qualifying Termination, an Early Retirement, an Intermediate Retirement, or a Normal Retirement during a Performance Period, a Change in Control occurs while the Subject Award is outstanding, then the Tranche RIUs or Certified RIUs, if any, as applicable, shall remain eligible for vesting or vest, if at all, pursuant to clause (x), (y), or (z) as follows:

(x) Qualifying Termination: If such a Qualifying Termination occurs prior to a given Tranche Valuation Date, then (A) the relevant TSR Tranche RIUs shall remain eligible for vesting, subject to the attainment and certification of Qualifying Performance and any Certified RIUs relating to such TSR Tranche RIUs shall be adjusted for the Prorated Amount and (B) the relevant CF Tranche RIUs shall be deemed to vest as Certified RIUs at the "Target" performance level, as adjusted for the Prorated Amount, as of the date of such Change in Control. For the avoidance of doubt, such a Qualifying Termination that occurs on or after a given Tranche Valuation Date is addressed in Section 3(c)(i)(x)(1) above or Section 3(d) below, as applicable.

(y) Early Retirement or Intermediate Retirement: If such an Early Retirement or Intermediate Retirement occurs prior to a given Tranche Valuation Date, then, subject to Participant satisfying the Retirement Conditions, (A) the relevant TSR Tranche RIUs shall remain eligible for vesting, subject to the attainment and certification of Qualifying Performance and any Certified RIUs relating to such TSR Tranche RIUs shall be adjusted for the Prorated Amount and (B) the relevant CF Tranche RIUs shall be deemed to vest as Certified RIUs at the "Target" performance level, as adjusted for the Prorated Amount, as of the date of such Change in Control. For the avoidance of doubt, such an Early Retirement or Intermediate Retirement that occurs on or after a given Tranche Valuation Date is addressed in Section 3(c)(i)(y)(1) above or Section 3(d) below, as applicable.

(z) Normal Retirement: If such a Normal Retirement occurs prior to a given Tranche Valuation Date, then, subject to Participant satisfying the Retirement Conditions, (A) the relevant TSR Tranche RIUs shall remain eligible for vesting, subject to the attainment and certification of Qualifying Performance (without adjustment for the Prorated Amount) and (B) the relevant CF Tranche RIUs shall be deemed to vest as Certified RIUs at the "Target" performance level (without adjustment for the Prorated Amount) as of the date of such Change in Control. For the avoidance of doubt, such a Normal Retirement that occurs on or after a given Tranche Valuation Date is addressed in Section 3(c)(i)(z)(1) above or Section 3(d) below, as applicable.

(iv) Death. If Participant's death occurs while the Subject Award is outstanding, then the Tranche RIUs or Certified RIUs, if any, as applicable, shall vest, if at all, pursuant to clause (x) or (y) as follows:

(x) If such a death occurs on or after a given Tranche Valuation Date for which Qualifying Performance is attained and certified, then the relevant Certified RIUs shall vest (without adjustment for the Prorated Amount) as of the date of such death.

(y) If such a death occurs prior to a given Tranche Valuation Date, then the relevant Tranche RIUs shall be deemed to vest as Certified RIUs at the "Target" performance level (without adjustment for the Prorated Amount) as of the date of such death.

(v) Disability. If the Participant's Qualifying Disability occurs while the Subject Award is outstanding, then the Tranche RIUs or Certified RIUs, if any, as applicable, shall vest, if at all, pursuant to clause (x) or (y) as follows:

(x) If such Qualifying Disability occurs on or after a given Tranche Valuation Date for which Qualifying Performance is attained and certified, then the relevant Certified RIUs shall vest (without adjustment for the Prorated Amount) as of the date of such Qualifying Disability.

(y) If such Qualifying Disability occurs prior to a given Tranche Valuation Date, then the relevant Tranche RIUs shall be deemed to vest as Certified RIUs at the "Target" performance level (without adjustment for the Prorated Amount) as of the date of such Qualifying Disability.

(vi) Section 409A Considerations.

(x) *Change in Control*. To the extent that the vesting under Section 3(c)(iii) or Section 3(d) relates to any Subject Tranche that is subject to Section 409A of the Code (a "***409A Subject Tranche***"), such vesting shall occur only if the applicable Change in Control constitutes "change in the ownership or effective control" of the Company within the meaning of Treas. Reg. Section 1.409A-3(i)(5). If such Change in Control does not constitute such a "change in the ownership or effective control" of the Company, the Tranche RIUs with respect to such 409A Subject Tranche shall remain eligible for vesting in accordance with the other provisions of this Section 3, as applicable.

(y) *Qualifying Disability*. To the extent that the vesting under Section 3(c)(vi) relates to any 409A Subject Tranche, (A) such vesting shall occur only if Participant incurs a "disability" within the meaning of Treas. Reg. Section 1.409A-3(i)(4), or (B) if clause (A) is not applicable, such vesting of the Certified RIUs described in Section 3(c)(vi) shall be dependent on Participant incurring a Separation from Service in connection with his or her Qualifying Disability. In such event, the Separation from Service shall be deemed as a Normal Retirement that is not subject to the Retirement Conditions solely for purposes of establishing the timing for when such vesting is deemed to occur for purposes of this Agreement.

(d) Change in Control Resulting in Delisting. Anything to the contrary herein notwithstanding, if a Change in Control occurs while the Subject Award is outstanding that results in the Company ceasing to be listed on a national securities exchange (a "***Delisting Change in Control***"), then the Tranche RIUs or Certified RIUs, if any, as applicable, shall vest, if at all, as follows:

(i) If such a Delisting Change in Control occurs on or after a given Tranche Valuation Date for which Qualifying Performance is attained and certified, then, subject to Participant satisfying the Retirement Conditions applicable to his or her Retirement, if any, the relevant Certified RIUs (without adjustment for the Prorated Amount) shall be deemed to vest as of (A) the applicable date pursuant to Section 3(c) if such Delisting Change in Control occurs on or after a Qualifying Termination, Retirement, death, or Qualifying Disability, (B) the date of a Qualifying Termination, Retirement, death, or Qualifying Disability, as applicable, if the Delisting Change in Control occurs prior to a Qualifying Termination, Retirement, death, or Qualifying Disability, as applicable, or (C) the applicable date pursuant to Section 3(a) above if not otherwise vested pursuant to the foregoing clauses.

(ii) If such a Delisting Change in Control occurs prior to a given Tranche Valuation Date, then, subject to Participant satisfying the Retirement Conditions applicable to his or her Retirement, if any, the relevant Tranche RIUs shall be deemed to vest as Certified RIUs at the "Target" performance level as of (A) the date of such Delisting Change in Control if the Delisting Change in Control occurs on or after a Qualifying Termination, Retirement, death, or Qualifying Disability, as applicable (in which case, such vesting shall be adjusted for the Prorated Amount for a Qualifying Termination, an Early Retirement, and an Intermediate Retirement and otherwise occur without adjustment for the Prorated Amount), (B) the date of a Qualifying Termination, Retirement, death, or Qualifying Disability, as applicable, if the Delisting Change in Control occurs prior to the Qualifying Termination, Retirement, death, or Qualifying Disability, as applicable, which vesting shall occur without adjustment for the Prorated Amount, or (C) the applicable date pursuant to Section 3(a) above if not otherwise vested pursuant to the foregoing clauses.

To the extent vesting applies pursuant to preceding paragraphs (i) and (ii) and the relevant Delisting Change in Control occurs prior to the delivery of Units, if any, described in Section 4 below, then the Company shall pay (in securities of a successor or surviving Person that are listed on a national securities exchange or if no such securities exist, then in cash) Participant an amount equal to the Change of Control Price (as defined in the Plan) for each of the relevant Certified RIUs for purposes of Section 4 below.

4. Certification of Performance; Payment.

(a) Certification. As soon as reasonably practicable following the close of a Performance Period that relates to a Subject Tranche, the Committee shall determine and certify (i) the extent to which the applicable Performance Goal as described on Schedule B is attained, and (ii) if at least Qualifying Performance is attained with respect to such Performance Goal (i.e., Qualifying Performance applies for such Subject Tranche), the number of the Certified RIUs that relate to such Subject Tranche. Such certification shall be final, conclusive, and binding on Participant, and on all other Persons, to the maximum extent permitted by law; *provided*, *however*, that Participant shall have the right at all reasonable times prior to or after any such certification to audit the books and records of the Committee and the Company, including the ability to make and retain copies of same, to the extent reasonably necessary to verify compliance with the terms and conditions of this Agreement, including, in particular, the calculations, workpapers, or other documents prepared and used in connection with making any such certification. For the avoidance of doubt, the Committee shall be deemed to have completed the certifications with respect to clauses (i) and (ii) above when vesting is deemed to occur at the "Target" performance level pursuant to Section 3(c) or Section 3(d).

(b) Payment. Subject to the "***Six-Month Delay Toggle***" (as defined in Section 15 of this Agreement), Units representing Certified RIUs shall be delivered to Participant no later than (i) if vesting occurs pursuant to Section 3(c), the 15th day of the third calendar month following the date on which vesting occurs (it being understood that in circumstances where Tranche RIUs remain eligible for vesting as Certified RIUs pursuant to Section 3(c), Units relating to the applicable Certified RIUs shall be delivered no later than the 15th day of the third calendar month following the relevant Tranche Valuation Date) and (ii) otherwise, 75 days following the End Date. Such Units representing Certified RIUs shall be delivered free of all restrictions to Participant or Participant's beneficiary or estate, as the case may be (it being understood that the entry on the transfer agent's books or the delivery of the certificate(s) with respect to such Units shall constitute delivery of such Units for purposes of this Agreement).

5. Distribution Equivalent Payment Rights. Each Subject Tranche hereunder includes a tandem award of Distribution Equivalent Rights that shall apply throughout the period in which the Subject Award is outstanding. Such Distribution Equivalent Rights shall entitle Participant to receive cash payments equal to the cash distributions made by the Company (on a per Unit basis) in respect of its outstanding Units generally ("***General Distributions***"). Except as provided below, such cash payments ("***Distribution Equivalent Payments***") shall be payable to the extent the Tranche RIUs that relate to such Subject Tranche ultimately vest as Certified RIUs pursuant to this Agreement. No Distribution Equivalent Payments shall be made if such Tranche RIUs do not vest as Certified RIUs, are forfeited, or are otherwise canceled. Accordingly, (i) payment of such Distribution Equivalent Payments shall be made at the same time, and shall be subject to the same conditions, as are applicable to the delivery of Units with respect to such Certified RIUs (the "***Delivered Units***"), and (ii) the amount of such Distribution Equivalent Payments shall be equal to the aggregate General Distributions that would have been made on the Delivered Units if such Delivered Units were held by Participant from the Grant Date through the date on which such Delivered Units are delivered to Participant. No interest shall be credited on any Distribution Equivalent Payments.

6. Taxes.

(a) REPRESENTATION. PARTICIPANT REPRESENTS THAT PARTICIPANT IS NOT RELYING ON THE COMPANY OR ITS AFFILIATES FOR ANY TAX ADVICE IN CONNECTION WITH THE RESTRICTED INCENTIVE UNITS AND THAT PARTICIPANT HAS BEEN, OR IS OTHERWISE HEREBY, ADVISED TO CONSULT WITH ITS OWN TAX ADVISOR WITH RESPECT TO THE AWARD OF RESTRICTED INCENTIVE UNITS UNDER THIS AGREEMENT.

(b) Withholding Matters.

(i) The Company, its Affiliates, as applicable, and Participant shall comply with all federal and state laws and regulations respecting the withholding, deposit, and payment of any income, employment (including Federal Insurance Contributions Act ("***FICA***") taxes), or other taxes relating to the Subject Award, including with respect to Distribution Equivalent Payments described in Section 5 of this Agreement. Such withholding shall be made by the Company or its Affiliates in accordance with the applicable withholding laws and regulations that are in effect at the time such withholding is required. Participant shall pay to the Company or its Affiliates, or make arrangements satisfactory to the Company or its Affiliates regarding payment of, any such withholding with respect to (A) Distribution Equivalent Payments and (B) the Restricted Incentive Units.

(ii) Participant shall, to the extent permitted by law, have the right to elect for the Company or its Affiliates to withhold Units to which Participant is otherwise entitled upon the vesting of the Restricted Incentive Units (or Participant may deliver to the Company other unrestricted Units owned by Participant or deliver to the Company or its Affiliates Units that Participant has previously acquired), in each case valued at the Fair Market Value of such Units at the time of such withholding by, or delivery to, the Company or its Affiliates, to satisfy the obligation of Participant under Section 6(b)(i) of this Agreement (it being understood that the Fair Market Value of all such Units withheld or delivered may not exceed the amount of withholding due based on the withholding rate(s) applied by the Company, in its discretion, in accordance with the applicable withholding laws and regulations that are in effect at the time such withholding is required); *provided*, *however*, that in no event shall any Units (or cash) that may be delivered hereunder be used to satisfy any FICA taxes that become due as a result of Participant being or becoming eligible for Retirement, Qualifying Termination or Qualifying Disability without having undergone such termination. Any payment of required withholding taxes by Participant in the form of Units shall not be permitted if it would result in an accounting charge with respect to such Units used to pay such taxes unless otherwise approved by the Committee.

(iii) Any provision of this Agreement to the contrary notwithstanding, if Participant does not otherwise satisfy the obligations of Participant under Section 6(b)(i) of this Agreement, Participant acknowledges and agrees that the Company and its Affiliates shall, to the extent permitted by law, have the right to deduct from any payments of any kind otherwise due from the Company or its Affiliates to or with respect to Participant, whether or not pursuant to this Agreement or the Plan and regardless of the form of payment, any federal, state, or local taxes of any kind required by law to be withheld with respect to any Distribution Equivalent Payments or Restricted Incentive Units hereunder.

7. Non-Assignability. Neither the Subject Award nor the Restricted Incentive Units is assignable or transferable by Participant, and, the Restricted Incentive Units shall not be assigned, alienated, pledged, attached, sold, or otherwise transferred or encumbered by Participant in any manner.

8. Entirety and Modification. This Agreement (including all schedules hereto) contains the entire agreement between the parties hereto with respect to the subject matter hereof and supersedes any and all prior agreements, whether written or oral, between such parties relating to such subject matter. Subject to Section 15.2 of the Plan, no modification, alteration, amendment, or supplement to this Agreement shall be valid or effective unless the same is in writing and signed by the party against whom it is sought to be enforced.

9. Severability. If any provision of this Agreement is held to be unenforceable, this Agreement shall be considered divisible, and such provision shall be deemed inoperative to the extent it is unenforceable, and in all other respects this Agreement shall remain in full force and effect; *provided, however*, that if any such provision may be made enforceable by limitation thereof, then such provision shall be deemed to be so limited and shall be enforceable to the maximum extent permitted by applicable law.

10. Gender. Words used in this Agreement which refer to Participant and denote the male gender shall also be deemed to include the female gender or the neuter gender when appropriate.

11. Employment or Service. Nothing in this Agreement shall confer upon Participant any right to continue in the employ or service of the Company or its Affiliates, nor shall this Agreement interfere in any manner with the right of the Company or its Affiliates to terminate the employment or service of Participant with or without Cause at any time.

12. Incorporation of Plan Provisions. This Agreement is made pursuant to the Plan and is subject to all of the terms and provisions of the Plan as if the same were fully set forth herein. In the event that any provision of this Agreement conflicts with the Plan, the provisions of the Plan shall control. Participant acknowledges receipt of a copy of the Plan and agrees that all decisions under and interpretations of the Plan by the Committee shall be final, binding, and conclusive upon Participant.

13. Headings. The headings of the various sections and subsections of this Agreement have been inserted for convenient reference only and shall not be construed to enlarge, diminish, or otherwise change the express provisions hereof.

14. Governing Law. This Agreement shall be governed by and construed in accordance with the laws of the state of Delaware (regardless of the laws that might otherwise govern under applicable Delaware principles of conflicts of law).

15. Section 409A. The compensation payable pursuant to the Subject Award is intended to be exempt from, or otherwise in compliance with, Section 409A of the Code and this Agreement shall be administered and construed to the fullest extent possible to reflect and implement such intent. For purposes of Section 409A of the Code, each Subject Tranche shall be treated as a right to receive a separate and distinct payment. Anything to the contrary herein notwithstanding, if, at the time of a Participant's Separation from Service with the Company and its Affiliates, such Participant is a "specified employee" (as defined in Section 409A of the Code), and the deferral of

the commencement of any amount of the payments or benefits otherwise payable pursuant to the Plan is necessary in order to prevent any accelerated or additional tax under Section 409A of the Code, then, to the extent permitted by Section 409A of the Code, such payments or benefits hereunder (without any reduction in the payments or benefits ultimately paid or provided to Participant) will be deferred until the earlier to occur of (i) Participant's death or (ii) the first business day that is six months following Participant's Separation from Service with the Company and its Affiliates(the "***Six-Month Delay Toggle***"). Any payments or benefits deferred due to the Six-Month Delay Toggle will be paid in a lump sum (without interest) to Participant on the earliest to occur of clause (i) or (ii) in the immediately preceding sentence.

16. No Voting Rights. Anything to the contrary herein notwithstanding, in no event shall Participant have any right to vote any, or to exercise any other rights, powers, and privileges of a holder of the Units with respect to any Restricted Incentive Units granted hereunder until such time that (i) the Performance Period applicable to such Restricted Incentive Units or a portion thereof shall have expired (and all other conditions to payment with respect thereto have been fulfilled), (ii) such Restricted Incentive Units are converted into the right to receive Units, and (iii) such Units are delivered to Participant.

17. Counterparts. This Agreement may be signed in counterparts, each of which shall be deemed an original and all of which shall constitute one and the same agreement.

IN WITNESS WHEREOF, the parties hereto have executed this Agreement as of the Grant Date.

ENLINK MIDSTREAM, LLC
By: EnLink Midstream Manager, LLC

By:____
Barry E. Davis
Chairman and Chief Executive Officer

PARTICIPANT:

____
____

SCHEDULE A
SUBJECT TRANCHE LISTING

Tranche Number	Relevant Performance Period for Subject Tranche	Relevant Performance Goal for Subject Tranche	Number of Restricted Incentive Units under Subject Tranche
1	First Performance Period	TSR	[●]
2	Second Performance Period	TSR	[●]
3	Third Performance Period	TSR	[●]
4	Cumulative Performance Period	TSR	[●]
5	First Performance Period	Cash Flow	[●]
6	Second Performance Period	Cash Flow	[●]
7	Third Performance Period	Cash Flow	[●]

SCHEDULE B
PERFORMANCE PERIOD, PERFORMANCE GOALS, AND PAYOUT AMOUNTS

1 . Performance Period. The number of Tranche RIUs that relate to a Subject Tranche, which can vest as Certified RIUs pursuant to the Subject Award, shall be calculated based on the level of Performance Goal achievement over the Performance Period that relates to such Subject Tranche.

2. Performance Goals. The Performance Goal with respect to a Subject Tranche shall be based on either total shareholder return ("***TSR***") or Cash Flow as such terms are further described below.

3 . TSR-Related Definitional Matters and Vesting Requirements. At the end of each Performance Period, the TSR for the Company and for each Peer Company (as described below) shall be determined pursuant to the following formula and in accordance with the following definitions and rules:

TSR	=	((Closing Average Value - Opening Average Value) + Reinvested Dividends) ÷ Opening Average Value*

*The result shall be rounded to the nearest hundredth of one percent (.01%).

(a) "***Closing Average Value***" means the average value of the common equity security for the 30 trading days ending on the last day of the Performance Period, which shall be calculated as follows: (A) determine the closing price of the common equity security on each trading date during 30-day period and (B) average the amounts so determined for the 30-day period.

(b) "***Opening Average Value***" means the average value of the common equity security for the 30 trading days preceding the start of the Performance Period, which shall be calculated as follows: (A) determine the closing price of the common equity security on each trading date during the 30-day period and (B) average the amounts so determined for the 30-day period.

(c) "***Reinvested Dividends***" means the dollar amount equal to (A) the aggregate number of the Company's common units / shares (including fractional common units / shares) that could have been purchased during the Performance Period had each cash distribution / dividend paid on one common unit / share at the beginning of the Performance Period been immediately reinvested in additional units / shares (or fractional common units / shares) at the closing selling price per common unit / share on the applicable distribution / dividend payment date (it being understood that the calculation in this clause (A) will include a compounding of distributions / dividends paid on common units / shares (or fractional common units / shares) "purchased" during the Performance Period from prior distribution / dividend "reinvestments") multiplied by (B) the Closing Average Value.

(d) Each of the foregoing amounts shall be equitably adjusted for share / unit splits, stock dividends or unit distributions, recapitalizations, and other similar events affecting the common equity securities in question.

(e) The Committee shall determine the number of Tranche RIUs that vest, if at all, as Certified RIUs pursuant to this Agreement based on the Company's relative TSR ranking in respect of the Performance Period as compared to the TSR ranking of the Peer Companies as follows:

Performance Level	The Company's Achieved TSR Percentile Position Relative to Peer Companies*	Associated Individual Payout Level (expressed as a percentage of the Tranche RIUs)
Below Threshold	Less than 25%	0%
Threshold	Equal to 25%	50%
Target	Equal to 50%	100%
Maximum	Greater than or Equal to 75%	200%

*If the Company's achieved TSR percentile position is between the Threshold and Target performance levels or if the Company's achieved TSR percentile position is between the Target and Maximum performance levels, then the associated individual payout level will be interpolated on a linear basis. If the Company's final TSR value is equal to the TSR value of a Peer Company, the Committee shall assign the Company the higher ranking.

(f) The Peer Companies are the companies set forth on Schedule C to this Agreement; *provided*, *however*, that the Peer Companies will be subject to change as follows:

(i) If on or before the date that is 30-trading days into a given Performance Period, a Peer Company enters into, becomes subject to, or is the subject of a definitive agreement or a filing made with the SEC contemplating an acquisition, merger, tender offer, or other similar transaction (regardless of whether such transaction is a Simplification Transaction or otherwise) (collectively, a "***Transaction***") that involves such Peer Company and that, if consummated, would result (or reasonably be expected to result) in such Peer Company ceasing to be traded on a national securities exchange ("***Traded***"), then such Peer Company will be eliminated from the TSR calculations for all Performance Periods that end on a date subsequent to the date of such definitive agreement or SEC filing, as applicable (it being understood that previously certified results for a Performance Period will be unimpacted by the foregoing). If, however, such Transaction is rescinded, revoked, terminated, or abandoned, then such Peer Company will remain a Peer Company and again be subject to all of the terms set forth herein (it being understood that previously certified results for a Performance Period will be unimpacted by the foregoing).

(ii) If on or after the date that is 31-trading days into a given Performance Period and before the last day of the relevant Performance Period, a Peer Company enters into, becomes subject to, or is the subject of a definitive agreement or a filing made with the SEC contemplating a Transaction (other than a Simplification Transaction, which is addressed below) that involves such Peer Company and that, if consummated, would result (or reasonably be expected to result) in such Peer Company ceasing to be Traded, then such Peer Company will be fixed above or below the Company for relative TSR purposes calculating the Company's and the applicable Peer Company's TSRs using the trading day preceding the date on which the public became aware of such a definitive agreement or SEC filing, as applicable, as the end date for "Closing Average Value" purposes. If such calculation results in such Peer Company being fixed above the Company, then the Committee shall assign the Peer Company with a TSR that places such Peer Company at the top of the TSR rankings, and if fixed below the Company, then the Committee shall assign the Peer Company with a TSR that places such Peer Company at the bottom of the TSR rankings, in each case, for all Performance Periods that end on a date subsequent to the date of the definitive agreement or SEC filing, as applicable (it being understood that previously certified results for a Performance Period will be unimpacted by the foregoing). If, however, such Transaction is rescinded, revoked, terminated, or abandoned, then such Peer Company will remain a Peer Company and again be subject to all of the terms set forth herein (it being understood that previously certified results for a Performance Period will be unimpacted by the foregoing).

(iii) If on or after the date that is 31-trading days into a given Performance Period and before the last day of the relevant Performance Period, a Peer Company enters into, becomes subject to, or is the subject of a definitive agreement or a filing made with the SEC contemplating a Simplification Transaction that involves such Peer Company and that, if consummated, would result (or reasonably be expected to result) in such Peer Company ceasing to be Traded, then the survivor of such Simplification Transaction that remains Traded shall be deemed to have been and to be a Peer Company (in each case, for purposes of each component of the TSR calculation) for all Performance Periods that end on a date subsequent to the date of such definitive agreement or SEC filing, as applicable (it being understood that previously certified results for a Performance Period will be unimpacted by the foregoing). If, however, such Simplification Transaction is rescinded, revoked, terminated, or abandoned, then such Peer Company will remain a Peer Company and again be subject to all of the terms set forth herein (it being understood that previously certified results for a Performance Period will be unimpacted by the foregoing).

(iv) A Peer Company that is both involved in a bankruptcy proceeding and ceases to be Traded during a Performance Period will remain a Peer Company but shall be deemed to have a TSR of negative 100% (-100%) for all Performance Periods that end on a date subsequent to the date of such delisting. A Peer Company that is involved in a bankruptcy proceeding, but remains Traded will remain a Peer Company and no adjustment shall be made.

(v) A Peer Company that ceases to be Traded during a Performance Period for a reason other than one contemplated in clauses (i) through (iv) above will remain a Peer Company but shall be deemed to have a TSR of negative 100% (-100%) for all Performance Periods that end on a date subsequent to the date of such delisting.

(g) "***Simplification Transaction***" means a transaction in the form of what is known in the MLP space as a "simplification" transaction and where the operating assets of the master limited partnership involved in such transaction constitute substantially all of the assets owned by the relevant parent entity involved in such transaction.

4. Cash Flow-Related Definitional Matters and Vesting Requirements.

(a) "***Cash Flow***" with respect to any relevant Performance Period shall consist of the measurement "free cash flow after distributions" ("***FCFAD***") and shall be calculated consistent with the Company's most relevant published financial results or guidance for a given Performance Period (the applicable "***Reference Year***") and means, (A) the Company's Adjusted EBITDA (as defined and calculated consistent with the Company's most relevant published financial results or guidance) minus (B) the sum of (w) interest expense, net of interest income, (x) accrued cash distributions on Series B Preferred Units and Series C Preferred Units paid or expected to be paid, (y) cash distributions paid or expected to be paid on the Company's common units, and (z) capital expenditures (including both maintenance and capital expenditures, but excluding capital expenditures that were contributed by other entities and relate to the non-controlling interest share of the Company's consolidated entities) plus (C) proceeds from sales of property and equipment. For the avoidance of doubt, actual FCFAD for any applicable Reference Year shall be calculated on a pre-bonus basis (*i.e*., before the STI payout).

(b) Prior to the certification of FCFAD performance by the Committee for a given Reference Year, Target FCFAD (as set forth in the chart below) may be adjusted for the following items: (i) changes in the common distribution rate, or special distributions, each as approved by the Board, (ii) growth capital expenditures for unbudgeted projects approved during the Reference Year for which primary financial benefits will be realized after the Reference Year as well as any cash flow amounts from such projects which are realized in the Reference Year, and (iii) other extraordinary events or items occurring during the Reference Year. Management shall prepare a list of such adjustments, if any, on a quarterly basis for consideration by the Committee. If the Committee, acting in its discretion, approves any such adjustments, the Target FCFAD for such Reference Year shall be adjusted by the amount so approved.

(c) The Committee shall determine the number of Tranche RIUs that vest, if at all, as Certified RIUs pursuant to this Agreement based on the Company's actual achieved FCFAD for the Performance Period ending December 31, 2021, as compared to the Target FCFAD as follows:

Performance Level	Target FCFAD*‡	Associated Individual Payout Level (expressed as a percentage of the Tranche RIUs)
Below Threshold	Less than $243	0%
Threshold	Equal to $243	50%
Target	Equal to $300	100%
Maximum	Greater than or equal to $357	200%

*If the Company's actual achieved FCFAD is between the Threshold and Target performance levels or if the Company's achieved FCFAD is between the Target and Maximum performance levels, then the associated individual payout level will be interpolated on a linear basis.
‡Amounts shown above as Target FCFAD apply for the First Performance Period, are shown on a pre-bonus basis, and are shown before adjustments, if any, are made pursuant to paragraph (b), above. The successive Performance Period Target FCFAD will be updated as set forth in paragraph (d) below.

(d) For the Second Performance Period and the Third Performance Period, the Board, or the Committee, will establish the figures to be included in the column titled "Target FCFAD" in the chart above and will notify Participant of the same in writing no later than March 31 of the year in which the relevant Performance Period begins.

5 . Other Vesting Terms. Any fractional Certified RIUs resulting from the vesting thereof in accordance with this Agreement shall be rounded down to the nearest whole number. Any portion of the Tranche RIUs that does not vest as Certified RIUs of the end of the Performance Period shall be forfeited as of the end of the Performance Period.

SCHEDULE C
PEER COMPANIES

Antero Midstream GP	MPLX, LP
Cheniere Energy, Inc.	NGL Energy Partners
Crestwood Equity Partners, LP	NuStar Energy, LP
DCP Midstream, LP	ONEOK, Inc.
Enable Midstream Partners, LP	Phillips 66 Partners, LP
Energy Transfer, LP	Plains All American Pipeline, LP
Enterprise Products Partners, LP	Plains GP Holdings
Equitrans Midstream Corp.	Shell Midstream Partners
Genesis Energy, LP	Targa Resources Corp.
Hess Midstream Partners LP	The Williams Companies, Inc.
Holly Energy Partners	TC Pipelines, LP
Kinder Morgan, Inc.	Western Gas Equity Partners, LP
Magellan Midstream Partners, LP	

SCHEDULE D
RESTRICTIVE COVENANTS

For the avoidance of doubt, Participant only makes the agreements contemplated in, and is only bound by, this Schedule D in connection with his or her Early Retirement, Intermediate Retirement, or Normal Retirement. In partial consideration for Participant's access to confidential information (the access to which Participant hereby acknowledges) and eligibility for and receipt of the benefits provided by Early Retirement, Intermediate Retirement, or Normal Retirement by that certain Performance Unit Agreement to which this Schedule D is attached (the "***Agreement***"), Participant hereby agrees as follows:

1. Restrictive Covenants.

(i) *Covenant Not to Solicit Customers*. Participant agrees that while employed by a member of the Company Group and for a period of twelve (12) months after his or her Early Retirement, Intermediate Retirement, or Normal Retirement, as applicable, Participant shall not (i) persuade or encourage any Person that was a client or customer of EnLink Midstream, LLC or any of its direct or indirect subsidiaries (collectively, the "***Company Group***") at any time during the twelve (12) months prior to his or her Early Retirement, Intermediate Retirement, or Normal Retirement, as applicable, to cease conducting or fail to renew existing business with that member of the Company Group, or (ii) use any confidential or proprietary information of any member of the Company Group to directly or indirectly solicit business from, or to interrupt, disturb, or interfere with any member of the Company Group's relationships with, any Person that was a client or customer of any member of the Company Group at any time during the twelve (12) months prior to his or her Early Retirement, Intermediate Retirement, or Normal Retirement, as applicable.

(ii) *Covenant not to Solicit Employees.* Participant agrees that while employed by any member of the Company Group and for a period of twenty-four (24) months after his or her Early Retirement, Intermediate Retirement, or Normal Retirement, as applicable, Participant shall not solicit, endeavor to entice, or induce any employee of any member of the Company Group to terminate such Person's employment or service with such member or accept employment with anyone else; provided, however, that a general solicitation of the public for employment shall not constitute a solicitation hereunder.

2 . Specific Performance. Recognizing that irreparable damage will result to the Company Group in the event of the breach or threatened breach of any of the foregoing covenants and assurances by Participant contained in paragraph 1 of this Schedule D, and that the Company Group's remedies at law for any such breach or threatened breach will be inadequate, the members of the Company Group and their successors and assigns, in addition to such other remedies that may be available to them, shall be entitled to an injunction, including a mandatory injunction (without the necessity of (i) proving irreparable harm, (ii) establishing that monetary damages are inadequate, or (iii) posting any bond with respect thereto), to be issued by any court of competent jurisdiction ordering compliance with the Agreement or enjoining and restraining Participant, and each and every Person, firm, or company acting in concert or participation with him or her, from the continuation of such breach and, in addition thereto, he or she shall pay to such affected member of the Company Group all ascertainable damages, including costs and reasonable attorneys' fees sustained by such affected member or members of the Company Group by reason of the breach or threatened breach of said covenants and assurances.

3 . Clawback. Participant agrees that in the event that the Committee determines that Participant has breached any term of this Schedule D, in addition to any other remedies at law or in equity that any affected member of the Company Group may have available to it or them, the Committee may in its sole discretion require that Participant, within five (5) business days of receipt of written demand therefor, repay to the Company the amount of any Distribution Equivalent Payments paid to Participant pursuant to Section 5 of the Agreement and return to the Company the Units (or other benefits) delivered to Participant in connection with Section 4 of the Agreement (or in the event Participant has ceased to hold such Units (or other benefits), an amount equal to the Fair Market Value thereof as in effect as of the date of such written demand).

4. Miscellaneous.

(a) Participant has carefully read and considered the provisions of this Schedule D and, having done so, agrees that the restrictions set forth in this Schedule D (including the relevant time periods, scope of activity to be restrained, and the geographical scope) are fair and reasonable and are reasonably required for the protection of the interests of the Company Group and their respective officers, directors, managers, employees, creditors, partners, members, and unitholders. Participant understands that the restrictions contained in this Schedule D may limit his or her ability to engage in a business similar to the business of any member of the Company Group, but acknowledges that he or she will receive sufficiently high remuneration and other benefits from the Company Group to justify such restrictions.

(b) The covenants and obligations of Participant set forth in this Schedule D are in addition to and not in lieu of or exclusive of, any other obligations and duties of Participant to the Company Group, whether express or implied in fact or in law.

(c) In the event that any provision of this Schedule D relating to the relevant time periods, scope of activity, and/or the areas of restriction hereunder shall be declared by a court of competent jurisdiction to exceed the maximum time period, scope, or areas such court deems reasonable and enforceable, the relevant time periods, scope of activity, and/or areas of restriction deemed reasonable and enforceable by the court shall become and thereafter be the maximum time period, scope of activity, and/or areas of restriction.

(d) The restrictive covenants set forth in this Schedule D are personal and not assignable by Participant but they may be assigned by the Company without notice to or consent of Participant to, and shall thereafter be binding upon and enforceable by, (i) any member of the Company Group, or (ii) any Person that acquires or succeeds to substantially all of the business or assets of any member of the Company Group (and such Person shall be deemed included to be in the definition of the "Company" and the "Company Group" for all purposes of this Schedule D).

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 Pipeline, LLC	Delaware
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 Funding, LLC	Delaware
EnLink Midstream GP, LLC	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 Partners, 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
Jefferson Island Storage & Hub, L.L.C.	Delaware
Ohio River Valley Pipeline, LLC	Delaware
OOGC Disposal Company I, LLC	Delaware
Sabine Hub Services LLC	Delaware
Sabine Pass Plant Facility Joint Venture	Texas
Sabine Pipe Line LLC	Delaware
SWG Pipeline, L.L.C.	Texas
TOM-STACK, LLC	Delaware

List of Subsidiary Guarantors

The following subsidiary (the “Subsidiary Guarantor”) of EnLink Midstream, LLC, a Delaware limited liability company (the “Company”), has guaranteed on a full, irrevocable, unconditional, and absolute basis, the debt securities of the Company listed below. The Company owns all of the outstanding common units representing limited partnership interests in the Subsidiary Guarantor.

<u>Subsidiary Guarantor</u>

- EnLink Midstream Partners, LP, a Delaware limited partnership.

<u>Debt Securities of the Company Guaranteed by the Subsidiary Guarantor</u>

- 5.375% Senior Notes due June 1, 2029

Exhibit 23.1

Consent of Independent Registered Public Accounting Firm

The Board of Directors of EnLink Midstream Manager, LLC:

We consent to the incorporation by reference in the registration statement No. 333-194395, No. 333-229347, and No. 333-229393 on Form S-8, No. 333-229806 on Form S-3 and No. 333-228278 on Form S-4 of EnLink Midstream, LLC of our report dated February 17, 2021, with respect to the consolidated balance sheets of EnLink Midstream, LLC and subsidiaries as of December 31, 2020 and 2019, and the related consolidated statements of operations, comprehensive loss, changes in members' equity, and cash flows for each of the years in the three-year period ended December 31, 2020, and the effectiveness of internal control over financial reporting as of December 31, 2020, which report appears in the December 31, 2020 annual report on Form 10-K of EnLink Midstream, LLC.

Our report contains an explanatory paragraph that refers to a change in the method of accounting for leases in 2019.

/s/ KPMG LLP

Dallas, Texas
February 17, 2021

Exhibit 31.1

CERTIFICATIONS

I, Barry E. Davis, certify that:

1. I have reviewed this annual report on Form 10-K of EnLink Midstream, LLC;

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 17, 2021

/s/ BARRY E. DAVIS

BARRY E. DAVIS

Chairman and Chief Executive Officer

(principal executive officer)

Exhibit 31.2

CERTIFICATIONS

I, Pablo G. Mercado, certify that:

1. I have reviewed this annual report on Form 10-K of EnLink Midstream, LLC;

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 17, 2021

/s/ PABLO G. MERCADO
Pablo G. Mercado
Executive Vice President and Chief Financial Officer
(principal financial officer)

Exhibit 32.1

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

In connection with the Annual Report of EnLink Midstream, LLC (the "Registrant") on Form 10-K of the Registrant for the year ended December 31, 2020 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 Manager, LLC, and Pablo G. Mercado, Executive Vice President and Chief Financial Officer of EnLink Midstream Manager, 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 17, 2021

/s/ BARRY E. DAVIS
Barry E. Davis
Chairman and Chief Executive Officer

Date: February 17, 2021

/s/ PABLO G. MERCADO
Pablo G. Mercado
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.