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, 2023

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. ☒

If securities are registered pursuant to Section 12(b) of the Act, indicate by check mark whether the financial statements of the registrant included in the filing reflect the correction of an error to previously issued financial statements. ☐

Indicate by check mark whether any of those error corrections are restatements that required a recovery analysis of incentive-based compensation received by any of the registrant's executive officers during the relevant recovery period pursuant to §240.10D-1(b). ☐

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 $ 2.6 billion on June 30, 2023, based on $10.60 per unit, the closing price of the common units as reported on the New York Stock Exchange on such date.

At February 14, 2024, there were 453,176,911 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.
Adjusted gross margin	Revenue less cost of sales, exclusive of operating expenses and depreciation and amortization. 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.
Agua Blanca Pipeline	The Agua Blanca Pipeline is a Delaware Basin intrastate natural gas pipeline servicing portions of Culberson, Loving, Pecos, Reeves, Ward, and Winkler counties and is owned by a joint venture between WhiteWater Midstream, LLC and MPLX LP.
Amarillo Rattler Acquisition	On April 30, 2021, we completed the acquisition of Amarillo Rattler, LLC, the owner of a gathering and processing system located in the Midland Basin.
AR Facility	An accounts receivable securitization facility of up to $500 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 and sustainability agent.
ASC	The Financial Accounting Standards Board Accounting Standards Codification.
ASC 606	ASC 606, *Revenue from Contracts with Customers.*
ASC 718	ASC 718, *Compensation—Stock Compensation*.
ASC 815	ASC 815, *Derivatives and Hedging.*
ASC 820	ASC 820, *Fair Value Measurements*.
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 transmission pipeline that connects ENLK's Riverside fractionator to Marathon Petroleum Corporation's Garyville refinery.
Barnett Shale	A natural gas producing shale reservoir located in North Texas.
Barnett Shale Acquisition	On July 1, 2022, we acquired all of the equity interest in the gathering and processing assets of Crestwood Equity Partners LP located in the Barnett Shale.
Bbl	Barrel.
Bbtu	Billion British thermal units.
Bcf	Billion cubic feet.
Beginning TSR Price	The beginning total shareholder return ("TSR") price, which is the closing unit price of ENLC on the grant date of the performance award agreement or the previous trading day if the grant date was not a trading day, is one of the assumptions used to calculate the grant-date fair value of performance award agreements.
BKV	BKV Corporation.
BLM	Bureau of Land Management.
Board	The board of directors of the Managing Member.
CCS	Carbon capture, transportation, and sequestration.
Cedar Cove JV	A joint venture in which we own a 30% 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.
Central Oklahoma Acquisition	On December 19, 2022, we acquired gathering and processing assets located in Central Oklahoma, including approximately 900 miles of lean and rich natural gas gathering pipeline and two processing plants with 280 MMcf/d of total processing capacity.
CFTC	U.S. Commodity Futures Trading Commission.
CO_2	Carbon dioxide.
Commission	U.S. Securities and Exchange Commission.
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 processing plants located in the Delaware Basin in Texas.
Devon	Devon Energy Corporation.
ENLC	EnLink Midstream, LLC together with its consolidated subsidiaries.
ENLC Class C Common Units	A class of non-economic ENLC common units equal to the number of Series B Preferred Units in order to provide certain voting rights with respect to ENLC to the holders of such Series B Preferred Units. The Class C Common Units were cancelled in September 2023 in connection with an amendment of ENLK's limited partnership agreement.

ENLK	EnLink Midstream Partners, LP or, when applicable, EnLink Midstream Partners, LP together with its consolidated subsidiaries.
Exchange Act	The Securities Exchange Act of 1934, as amended.
ExxonMobil	ExxonMobil Corporation.
FCDTCs	Futures and Cleared Derivatives Transactions Customer Agreements.
Federal Reserve	The Board of Governors of the Federal Reserve System of the United States.
FERC	Federal Energy Regulatory Commission.
GAAP	Generally accepted accounting principles in the United States of America.
Gal	Gallon.
GCF	A joint venture in which we own a 38.75% interest. Gulf Coast Fractionators owns an NGL fractionator in Mont Belvieu, Texas. The GCF assets were idled to reduce operating expenses in 2021 but are expected to resume operations in the first half of 2024.
General Partner	EnLink Midstream GP, LLC, the general partner of 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.
IRC	Internal Revenue Code.
ISDAs	International Swaps and Derivatives Association Agreements.
LIBOR	U.S. Dollar London Interbank Offered Rate.
LNG	Liquified natural gas.
Managing Member	EnLink Midstream Manager, LLC, the managing member of ENLC.
Matterhorn JV	A joint venture in which we own a 15% interest. The Matterhorn JV is constructing a pipeline designed to transport up to 2.5 Bcf/d of natural gas through approximately 490 miles of 42-inch pipeline from the Waha Hub in West Texas to Katy, Texas.
MEGA	Midland Energy Gathering Area in Midland, Martin, and Glasscock counties, Texas.
Midland Basin	A large sedimentary basin in West Texas.
MMbbls	Million barrels.
MMbtu	Million British thermal units.
MMcf	Million cubic feet.
MMgals	Million gallons.
MVC	Minimum volume commitment.
NGL	Natural gas liquid.
NGP	NGP Natural Resources XI, LP.
NYMEX	New York Mercantile Exchange.
NYSE	New York Stock Exchange.
Operating Partnership	EnLink Midstream Operating, LP, a Delaware limited partnership and wholly owned subsidiary of ENLK.
OPIS	Oil Price Information Service.
ORV	ENLK's Ohio River Valley crude oil, condensate stabilization, natural gas compression, and brine disposal assets in the Utica and Marcellus shales. In November 2023, we divested these assets. See "Item 8. Financial Statements and Supplementary Data—Note 3" for more information regarding our divestitures.
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.
Revolving Credit Facility	A $1.40 billion unsecured revolving credit facility entered into by ENLC, which includes a $500.0 million letter of credit subfacility. The Revolving Credit Facility is guaranteed by ENLK.
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.
SOFR	Secured overnight financing rate.
SPV	EnLink Midstream Funding, LLC, a bankruptcy-remote special purpose entity that is an indirect subsidiary of ENLC.
STACK	Sooner Trend Anadarko Basin Canadian and Kingfisher Counties in Oklahoma.

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 Exchange Act. All such filings on our website are available free of charge. Additionally, filings are available on the Commission’s website (www.sec.gov).

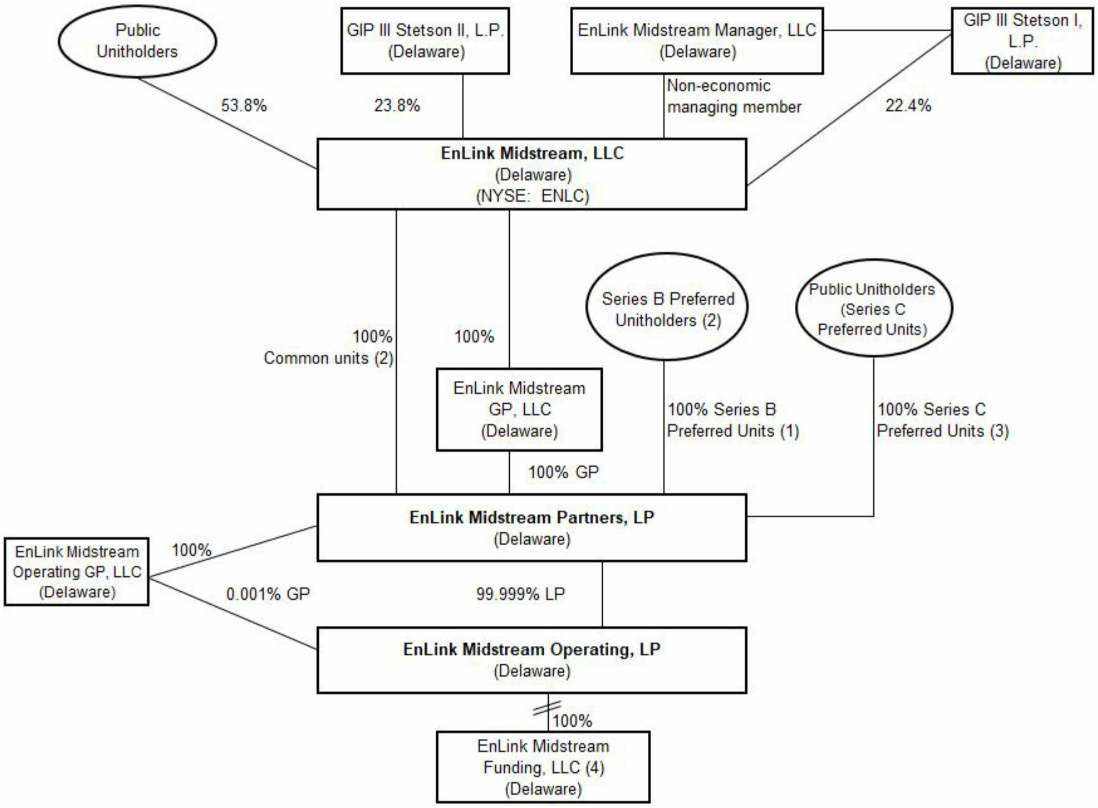
All of our midstream energy assets are owned and operated by ENLK and its subsidiaries. ENLC owns all of ENLK’s common units and also owns all of the membership interests of the General Partner. The General Partner manages ENLK’s operations and activities.

As of December 31, 2023, GIP, through GIP III Stetson I, L.P. and GIP III Stetson II, L.P, owns 46.2% of the outstanding limited liability company interests in ENLC. In addition to GIP’s equity interests in ENLC, GIP III Stetson I, L.P. maintains control over the Managing Member through its ownership of all the equity interests in the Managing Member.

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. 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.

For more information about our organization of the business before the year ended December 31, 2023, refer to “Item 1. Business—General” of our Annual Report on Form 10-K for the fiscal year ended December 31, 2022, filed with the Commission on February 15, 2023, and available here.

The following diagram depicts our organization and ownership as of December 31, 2023:



(1) Series B Preferred Units are exchangeable into ENLC common units on a 1-for-1.15 basis, subject to certain adjustments. The non-economic ENLC Class C Common Units previously held by the Series B Preferred Unitholders were cancelled in September 2023 in connection with an amendment of ENLK's limited partnership agreement. See "Item 8. Financial Statements and Supplementary Data—Note 9" for more information.
(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.
(4) EnLink Midstream Funding, LLC is a bankruptcy-remote special purpose entity that entered into the AR Facility in October 2020. See "Item 8. Financial Statements and Supplementary Data—Note 7" for more information regarding the AR Facility.

Our Operations

We primarily focus on owning, operating, investing in, and developing midstream energy infrastructure assets to provide midstream energy services, including:

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

As of December 31, 2023, our midstream infrastructure network includes approximately 13,600 miles of pipelines, 25 natural gas processing plants with approximately 5.8 Bcf/d of processing capacity, seven fractionators with approximately 316,300 Bbls/d of fractionation capacity, barge and rail terminals, product storage facilities, purchasing and marketing capabilities, 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 gathering 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 diameter pipelines for further transmission. Our processing plants 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. We also store natural gas and NGLs on behalf of third parties for a fee or to balance our own purchases and sales in marketing natural gas and NGLs for our customers.

Our large diameter natural gas transmission pipelines provide access to multiple domestic production basins to a variety of customers, such as industrial end-users, LNG facilities, and utilities. Our large diameter natural gas transmission pipelines are connected to our gathering systems or third party gathering systems, natural gas transmission pipeline systems, and natural gas storage caverns.

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 we transport NGLs from our West Texas and Central Oklahoma operations on third party pipelines 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, in addition to condensate stabilization. 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.

We manage and report our operations primarily according to the geography and the nature of the activity. 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 transmission pipelines, natural gas processing plants, natural gas and NGL storage facilities, and fractionation facilities located in Louisiana and, prior to its sale in November 2023, 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 Cana-Woodford, Arkoma-Woodford, northern Oklahoma Woodford, STACK, and adjacent areas;

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

- *Corporate Segment.* The Corporate segment includes our unconsolidated affiliate investments in the Cedar Cove JV in Oklahoma, GCF in South Texas, and the Matterhorn JV in West Texas, as well as our corporate assets and expenses.

For more information about our segment reporting, see “Item 8. Financial Statements and Supplementary Data—Note 16.”

Our Business Strategies

We develop, own, and operate midstream energy infrastructure assets and use these infrastructure assets to provide midstream services, including gathering and processing, long-haul transportation, fractionation, and storage, across a range of hydrocarbons, including natural gas, crude oil, NGLs, and CO_2. Our asset platforms operate in premier production basins, transportation hubs, and core demand centers, including the Permian Basin, Louisiana, Oklahoma, and North Texas.

Our primary aim is to use our portfolio of assets to gather, process, fractionate, transport, and store a growing amount of hydrocarbons along the supply chain from production basins in Texas, Oklahoma, and North Texas to Gulf Coast end-users, fractionators, and storage facilities or for transport to other domestic and international markets.

To support and grow our business prudently and profitably, we focus on the following:

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

- *Strategic Growth.* We believe our assets are positioned in key demand centers with growing end-user and export customers and are located in some of the most economically advantageous producing basins in the United States. We expect to grow our natural gas and NGL transportation network along the Gulf Coast by leveraging our existing infrastructure and operations to optimize our network of connections and expand our footprint. We also expect to grow our gathering and processing systems organically over time by meeting our customers' midstream service needs that result from their drilling activity in our areas of operation. From time to time, we may also make opportunistic and strategic acquisitions to further expand our business.

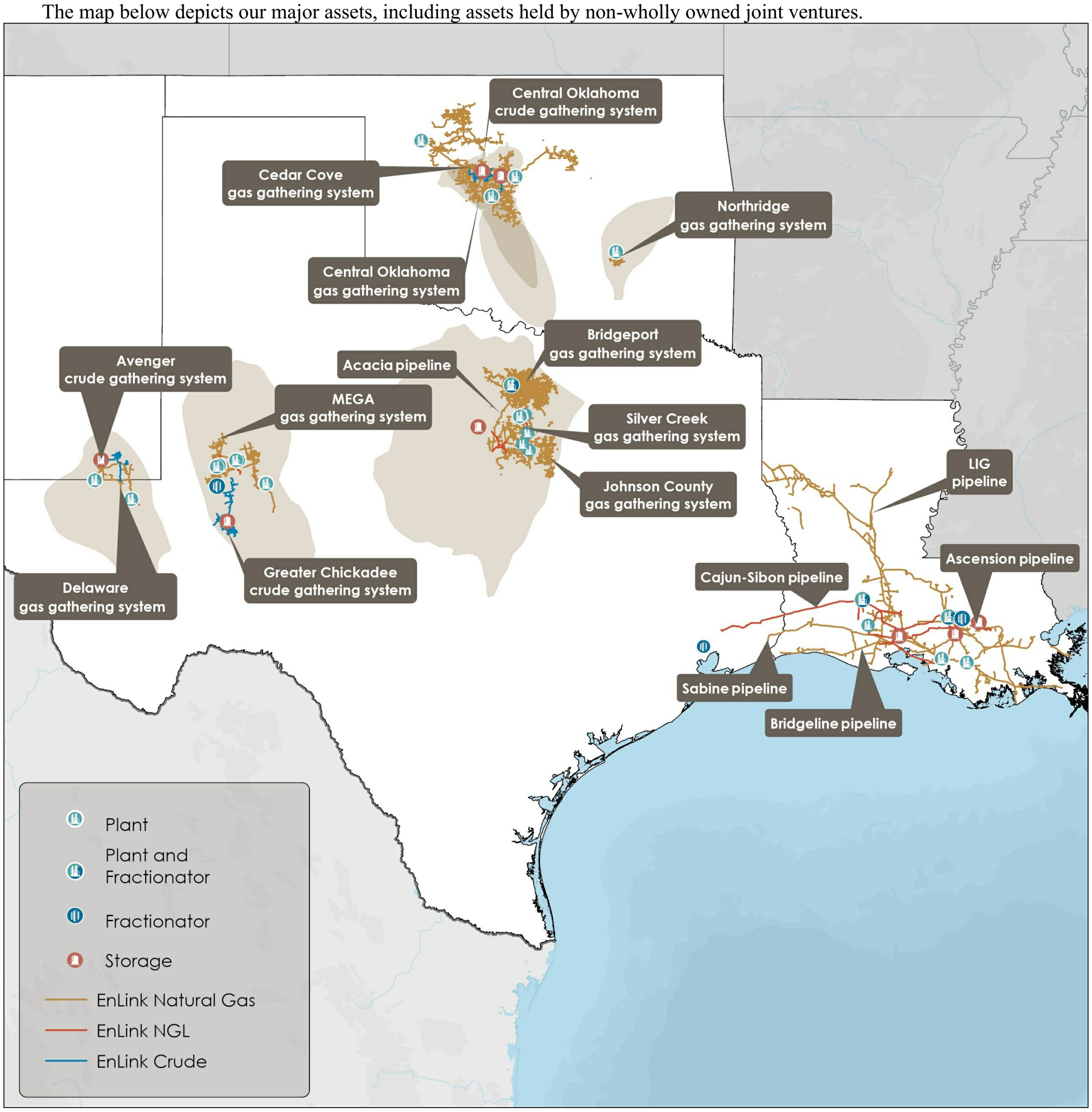
  We are also building a carbon transportation business in support of CCS along the Gulf Coast, including the Mississippi River industrial corridor in Louisiana, one of the highest CO_2 emitting regions in the United States. We believe our operating expertise, our customer relationships, and our existing asset footprint, including our extensive network of natural gas pipelines in Louisiana, provide us with an advantage in building a carbon transportation business and becoming the transporter of choice in the Gulf Coast region.

- *Operational Excellence and Innovation*. We have created a rigorous company-wide program of operational excellence 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, and enhance the scalability of our asset platforms for future growth.

- *Sustainability and Safety*. We operate our business responsibly and with regard for our employees, the environment, and the communities in which we operate. We are committed to operating safely and in an environmentally responsible manner. See "Human Capital" below for additional information on our employee policies and "Sustainability" below for more information on our sustainability and environmental efforts.

Our Assets

The map below depicts our major assets, including assets held by non-wholly owned joint ventures.



The following tables provide information about our assets as of and for the year ended December 31, 2023:

Gathering and Transmission Pipelines	Approximate Length (Miles)	Compression (HP)	Estimated Capacity (1)	Year Ended December 31, 2023 Average Throughput (2)
Natural gas pipelines				
Permian assets:				
MEGA gas gathering system	1,125	297,100	1,180	1,119,400
Delaware gas gathering system (3)	295	118,200	620	681,500
Permian natural gas pipelines (3)	1,420	415,300	1,800	1,800,900
Louisiana assets:				
Louisiana natural gas pipelines	3,040	106,300	3,975	2,495,000
Oklahoma assets:				
Central Oklahoma gas gathering system	2,890	256,490	1,560	1,190,000
Northridge gas gathering system	140	14,000	50	31,000
Oklahoma natural gas pipelines	3,030	270,490	1,610	1,221,000
North Texas assets:				
Bridgeport gas gathering system	2,795	189,340	827	714,000
Johnson County gas gathering system	280	49,000	400	82,100
Silver Creek gas gathering system	1,400	190,000	840	348,800
Acacia pipeline	130	16,000	920	434,500
North Texas natural gas pipelines	4,605	444,340	2,987	1,579,400
Total natural gas pipelines	12,095	1,236,430	10,372	7,096,300
NGL, crude oil, and condensate pipelines				
Permian assets:				
Permian crude gathering systems	500	—	290,000	165,300
Louisiana assets:				
Cajun-Sibon pipeline (4)	760	—	195,000	187,300
Ascension pipeline (5)	35	—	65,000	26,400
Louisiana NGL pipelines	795	—	260,000	213,700
Oklahoma assets:				
Central Oklahoma crude gathering system	200	—	160,000	25,300
Total NGL, crude oil, and condensate pipelines	1,495	—	710,000	404,300

(1) Estimated capacity for natural gas pipelines is MMcf/d. Estimated capacity for NGL, crude oil, condensate pipelines is Bbls/d.
(2) Average throughput for natural gas pipelines is MMbtu/d. Average throughput for NGL, crude oil, 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 gas gathering system includes only the Delaware Basin JV's compression capacity and does not include natural gas compressed by third parties on our system.
(4) Estimated capacity is based on an estimated mixture of NGLs shipped through the pipeline. A higher or lower functional capacity will occur depending on the composition of the transported product.
(5) Includes gross mileage, capacity, and throughput for the Ascension JV, which is owned 50% by us.

Processing Facilities	Processing Capacity (MMcf/d)	Year Ended December 31, 2023 Average Throughput (MMbtu/d)
Permian assets:		
MEGA system processing facilities	975	1,020,700
Delaware processing facilities (1)	635	641,700
Permian assets	1,610	1,662,400
Louisiana assets:		
Louisiana processing facilities (2)	1,478	167,600
Oklahoma assets:		
Central Oklahoma processing facilities	1,220	1,142,200
Northridge processing facility	200	39,800
Oklahoma assets	1,420	1,182,000
North Texas assets:		
Bridgeport processing facility	760	553,200
Silver Creek processing facilities (3)	505	181,400
North Texas assets	1,265	734,600
Total Processing Facilities	5,773	3,746,600

(1) The Lobo I processing plant, which accounts for 35 MMcf/d of processing capacity of the Delaware processing facilities, is not operational. Additionally, the processing capacity does not include an estimated 150 MMcf/d related to the Tiger II Processing Plant, which is currently under construction and is expected to be completed in the second quarter of 2024.

(2) The Blue Water, Eunice, and Plaquemine processing plants are not operational. These plants represented 193 MMcf/d, 350 MMcf/d, and 225 MMcf/d, respectively, for a total of 768 MMcf/d of the total processing capacity of the Louisiana processing facilities.

(3) The Azle, Goforth, Corvette, and West Johnson processing plants are not operational. These plants represented 50 MMcf/d, 30 MMcf/d, 125 MMcf/d, and 100 MMcf/d, respectively, for a total of 305 MMcf/d of the total processing capacity of the Silver Creek processing facilities.

Fractionation Facilities	Estimated NGL Fractionation Capacity (Bbls/d)	Year Ended December 31, 2023 Average Throughput (Bbls/d)
Permian assets:		
Mesquite terminal (1)	15,000	—
Louisiana assets:		
Plaquemine fractionation facility (2)	136,800	84,700
Riverside fractionation facility (2)	—	33,000
Plaquemine processing plant	8,500	1,000
Eunice fractionation facility	75,000	64,800
Louisiana assets	220,300	183,500
North Texas assets:		
Bridgeport processing facility	25,000	24,900
Corporate assets:		
GCF (3)	56,000	—
Total Fractionation Facilities	316,300	208,400

(1) The Mesquite terminal fractionator is not currently 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 136,800 Bbls/d.

(3) Volumes shown reflect our 38.75% ownership in GCF. The GCF fractionation facility was not operational in 2023 but is expected to resume operations in the first half of 2024.

Storage Assets	Storage Type	Estimated Design Capacity (1)	Estimated Working Capacity (1)
Permian assets:			
Avenger storage	Crude	0.1	0.1
Greater Chickadee storage	Crude	0.2	0.2
Louisiana assets:			
Belle Rose storage	Natural gas	9.6	6.5
Sorrento storage	Natural gas	4.9	2.5
Jefferson Island storage	Natural gas	3.0	2.0
Napoleonville storage	NGL	7.6	7.6
Oklahoma assets:			
Central Oklahoma storage	Crude	0.2	0.2
North Texas assets:			
North Texas storage	Natural gas	1.1	0.8

(1) Estimated design capacity and estimated working capacity for natural gas storage is Bcf . Estimated capacity for NGL and crude oil storage is MMbbls. Estimated design capacity includes the cushion necessary to operate storage facilities

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

- Natural Gas Gathering Systems. Our natural gas gathering pipelines in the Permian segment consist of the following:

  - *MEGA gas gathering system*. This gathering system in the Midland Basin serves as an interconnected system of pipelines and compressors to deliver natural 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 processing plants, which are owned by the Delaware Basin JV.

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

  - *Avenger crude gathering system.* Avenger crude gathering system is located in the northern Delaware Basin in Eddy and Lea counties in New Mexico.

  - *Greater Chickadee crude gathering system.* The Greater Chickadee crude gathering system delivers crude oil for customers to Enterprise Product Partners L.P.'s crude oil terminal in West Texas. The Greater Chickadee crude gathering system also includes multiple central tank batteries with pump, truck injection, and storage stations to maximize shipping and delivery options for producers.

- Natural Gas Processing Facilities. Our natural gas processing facilities in the Permian segment consist of the following:

  - *MEGA system processing facilities.* Our MEGA system 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 50 MMcf/d, the Midmar processing facilities with a capacity of 207 MMcf/d, the Riptide processing facility with a capacity of 270 MMcf/d, the War Horse processing plant with a capacity of 105 MMcf/d, and the Phantom processing plant with a capacity of 268 MMcf/d.

  - *Delaware processing facilities.* The Delaware processing facilities include our Lobo natural gas processing facilities and the Tiger I processing plant. Our Lobo natural gas processing facilities are located in Loving County, Texas and include Lobo I, Lobo II, and Lobo III processing plants which account for 35 MMcf/d, 140 MMcf/d, and 220 MMcf/d of processing capacity, respectively. The Lobo I processing plant is currently not operational. Our Tiger I processing plant is located in Culberson County, Texas, and accounts for 240 MMcf/d of processing capacity. The Tiger II Processing Plant is currently under construction and is expected to add 150 MMcf/d of processing capacity beginning in the second quarter of 2024. The Lobo processing facilities and the connected gathering system and the Tiger processing plants are owned by the Delaware Basin JV.

- Fractionation Facility. The Mesquite fractionator has an approximate capacity of 15,000 Bbls/d and is located at our MEGA system processing facilities. The Mesquite fractionator is not currently operational.

Louisiana Segment Assets. Our Louisiana segment assets consist of interstate and intrastate natural gas gathering and transmission pipelines, natural gas processing facilities, natural gas storage, NGL pipelines and storage, and four fractionation facilities.

- Natural Gas Transmission Pipelines and Gathering Systems. Our natural gas pipeline systems in the Louisiana segment include a portfolio of large capacity interconnections within the Gulf Coast pipeline grid, providing customers with access to multiple domestic production basins and a variety of customers, including major industrial customers located in the Mississippi River corridor between Baton Rouge, Louisiana and New Orleans, Louisiana, as well as utilities and Gulf Coast LNG facilities.

  - *Sabine pipeline.* The Sabine pipeline is an interstate natural gas pipeline system that offers both interruptible and firm transportation services to its customers. The Sabine pipeline is used to transport natural gas between Port Arthur, Texas and the Henry Hub. The Sabine pipeline owns and operates the Henry Hub, the official delivery mechanism and pricing point for Chicago Mercantile Exchange's NYMEX natural gas futures contracts as well as the OTC swaps traded on the Intercontinental Exchange.

  - *Bridgeline pipeline.* The Bridgeline pipeline is a Louisiana intrastate natural gas pipeline system providing transportation and storage services to a variety of customers including South Louisiana industrials, power companies, utilities, and Gulf Coast LNG facilities.

  - *Louisiana intrastate gas (LIG) pipeline.* The LIG pipeline is an intrastate natural gas gathering and transmission pipeline system providing a fully integrated wellhead to burner tip value chain that includes local gathering, processing, transmission, and treating services to Louisiana producers. The LIG pipeline is connected to several other natural gas pipelines, providing additional system supply, and the Jefferson Island storage facility.

- Natural Gas Processing and Storage Facilities. Our natural gas processing facilities and storage facilities in the Louisiana segment 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 gas 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 natural gas pipeline systems 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 natural gas storage facility is located in Assumption Parish, Louisiana. This facility is designed for injecting pipeline quality natural gas into storage or withdrawing stored natural gas for delivery by pipeline.

  - *Sorrento gas storage facility.* The Sorrento natural gas storage facility is located in Ascension Parish, Louisiana. This facility is designed for injecting pipeline quality natural gas into storage or withdrawing stored natural 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 and is connected to our extensive Louisiana natural gas system. This facility is designed for injecting pipeline quality natural gas into storage or withdrawing stored natural gas for delivery by pipeline.

  - *Non-Operational Processing Plants:*

    - *Blue Water gas processing plant.* We operate and own a 64.29% interest in the Blue Water natural gas processing plant. The Blue Water natural gas processing plant is located in Crowley, Louisiana and is connected to the Blue Water pipeline system. Our share of the plant's capacity is approximately 193 MMcf/d. The Blue Water natural gas processing plant is currently not operational and we do not expect to operate it 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. The Plaquemine processing plant is currently not operational 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. The Eunice processing plant is currently not operational and we do not expect the plant to operate in the near future unless volumes are sufficient to run the plant.

- NGL Pipeline Systems. Our NGL pipeline systems in the Louisiana segment consist of NGL pipelines and underground NGL storage.

  - *Cajun-Sibon pipeline*. The Cajun-Sibon pipeline transports unfractionated NGLs from interconnects near Mont Belvieu, Texas, and, from time to time, our Pelican processing plant in South Louisiana to either the Plaquemine or Eunice fractionators or to third-party fractionators when necessary.

  - *Ascension pipeline.* The Ascension pipeline is an NGL pipeline that connects our Riverside fractionator to Marathon Petroleum Corporation's Garyville refinery and is owned by the Ascension JV.

  - *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 the Louisiana segment that are connected to our processing facilities and to Mont Belvieu, Texas and other hubs through our Cajun-Sibon pipeline.

  - *Plaquemine fractionation facility.* The Plaquemine fractionator is located at our Plaquemine natural 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 136,800 Bbls/d of raw-make NGL products.

  - *Plaquemine natural gas processing plant.* In addition to the Plaquemine fractionation facility, the adjacent Plaquemine natural gas processing plant also has an on-site fractionator.

  - *Eunice fractionation facility.* The Eunice fractionation facility is located in South Central Louisiana. Liquids are delivered to the Eunice fractionation facility by the Cajun-Sibon pipeline. The Eunice fractionation facility 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 natural gas gathering pipelines, natural gas processing facilities, and crude oil gathering pipelines and storage in Southern and Central Oklahoma.

- Natural Gas Gathering Systems. Our natural gas gathering pipelines in the Oklahoma segment consist of the following:

  - *Central Oklahoma gas gathering system.* The Central Oklahoma gas gathering system serves the STACK play and adjacent areas.

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

- Natural Gas Processing Facilities. Our natural gas processing facilities in the Oklahoma segment consist of the following:

    - *Central Oklahoma processing facilities.* The Central Oklahoma processing facilities include three processing plants: the Chisholm processing plant, the Cana processing plant, and the Redcliff processing plant, acquired in the Central Oklahoma Acquisition in December 2022, which account for 600 MMcf/d, 400 MMcf/d, and 220 MMcf/d of processing capacity, respectively.

    - *Northridge processing facility.* Our Northridge processing facility is located in Hughes County in the Arkoma-Woodford Shale in Southeastern Oklahoma and accounts for 200 MMcf/d of processing capacity.

- Crude Oil Gathering Systems. Our crude and condensate assets in the Oklahoma segment have crude oil and condensate pipelines and above ground storage in Central Oklahoma. These assets consist of the following:

    - *Central Oklahoma crude gathering system.* Our Central Oklahoma crude gathering system include Black Coyote and Redbud, which operate in the core of the STACK play in Central Oklahoma.

North Texas Segment Assets. Our North Texas segment assets include natural gas gathering pipelines, a natural gas transmission system, a CO_2 capture system, natural gas processing facilities, and a fractionation facility in the Barnett Shale.

- Natural Gas Gathering Pipelines. Our natural gas gathering systems in the North Texas segment 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.

    - *Bridgeport lean gas gathering system.* Natural gas gathered on the Bridgeport lean gas gathering system is delivered to the Acacia pipeline and to intrastate pipelines without processing.

    - *Johnson County gas gathering system*. Natural gas gathered on this system is processed at our Silver Creek processing facilities.

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

- Natural Gas Transmission System. The Acacia pipeline is a transmission system that connects production from the Barnett Shale to markets in North Texas.

- CO_2 Capture System. Our CO_2 capture system captures and transports up to 250,000 metric tonnes per year of CO_2 separated from the lean natural gas in our North Texas gathering systems and from the rich natural gas delivered to our natural gas processing plant in Bridgeport, Texas. This CO_2 waste stream is then captured, compressed, transported, and sequestered by BKV.

- Natural Gas Processing Facilities and Storage Facility. Our natural gas processing facilities and storage facility in the North Texas segment consist of the following:

    - *Bridgeport processing facility.* Our Bridgeport processing facility, located in Wise County, Texas, is one of the largest processing plants in the U.S. with seven cryogenic turboexpander plants.

    - *Silver Creek processing facilities.* Our Silver Creek processing facilities is located in Weatherford, Azle, Fort Worth, Cleburne, Granbury, and West Johnson County, Texas, and includes five processing plants: the Azle plant, the Silver Creek plant, the Goforth plant, and the Corvette and West Johnson plants, which were both acquired in the Barnett Shale Acquisition in July 2022. These plants account for 50 MMcf/d, 200 MMcf/d, 30 MMcf/d, 125 MMcf/d, and 100 MMcf/d of processing capacity, respectively. The Azle, Goforth, Corvette, and West Johnson processing plants are currently not operational due to decreased volumes. In 2023, we began relocating the equipment and facilities associated with the Cowtown processing plant to the Delaware Basin JV in the Permian segment, where it will operate as the Tiger II processing plant. Currently, the processing capacity at the Silver Creek plant is sufficient to process all natural gas at our Silver Creek processing facilities.

- *North Texas storage facility.* The North Texas natural gas storage facility is located in Palo Pinto County, Texas.

- Fractionation Facility. Our Bridgeport processing facility in North Texas also has fractionation capabilities that provide operational flexibility. Under our current contracts, we own the NGLs that are allocated to BKV and we generate adjusted gross margin by selling the fractionated NGL products.

Corporate Segment Assets. Our Corporate segment assets primarily consist of our 38.75% ownership interest in GCF, 30% ownership interest in the Cedar Cove JV, and 15% ownership interest in the Matterhorn JV.

- *GCF*. We own a 38.75% interest in GCF. GCF owns an NGL fractionator located on the Gulf Coast at Mont Belvieu, Texas. 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 were idled to reduce operating expenses. In January 2023, we and our partners began the process to restart the GCF assets and expect operations to commence in the first half of 2024.

- *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. All natural gas gathered by the Cedar Cove JV is processed by our Central Oklahoma processing facilities.

- *Matterhorn JV.* We own a 15% interest in the Matterhorn JV. The Matterhorn JV is constructing a pipeline designed to transport up to 2.5 Bcf/d of natural gas through approximately 490 miles of 42-inch pipeline from the Waha Hub in West Texas to Katy, Texas (the "Matterhorn Express Pipeline"). Supply for the Matterhorn Express Pipeline will be sourced from multiple upstream connections in the Permian Basin, including direct connections to processing facilities in the Midland Basin through an approximately 75-mile lateral, as well as a direct connection to the 3.2 Bcf/d Agua Blanca Pipeline. The Matterhorn Express Pipeline is expected to be in service in the third quarter of 2024, pending the receipt of customary regulatory and other approvals.

Industry Overview

The midstream industry is the link between the exploration and production of natural gas and crude oil and condensate and the delivery of these commodities or their components to end-user markets.

Natural gas gathering. The natural gas gathering process follows the drilling of wells into natural 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 natural 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 natural gas at an existing pressure is compressed to a desired higher pressure, allowing natural 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 natural 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 natural 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 natural 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 natural 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 a variety of customers, including industrial end-users, utilities, LNG facilities, and to other natural gas transmission 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.

Carbon Capture and Sequestration. The midstream industry is participating in the energy transition in innovative ways, including through the development of carbon capture and sequestration infrastructure. CCS is a process in which CO_2 emitted by industrial emitters is captured and transported through pipelines for permanent sequestration in underground formations. As part of this process, we are building a carbon transportation business in support of CCS along the Gulf Coast, including along the Mississippi River industrial corridor in Louisiana, one of the highest CO_2 emitting regions in the United States.

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, as well as in the marketing, transportation, and processing of natural gas, NGLs, crude oil, and condensate. In addition, we face strong competition in the building of our CCS transportation business. 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. For our CCS transportation development projects, our competitors include other midstream service providers along the Gulf Coast, some of whom may have existing pipelines that may be available to transport CO_2. 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 natural gas and NGL transmission pipelines have connections with major intrastate and interstate natural gas and NGL pipelines. 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 related assets to determine the availability of natural gas, NGLs, crude oil, and condensate supply for our gathering systems and related 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 gathering systems and related 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 Key Customers

We are subject to the 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 natural gas, NGLs, crude oil, and condensate 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 other macro-economic factors may result in a reduction in our customers' liquidity and ability to make payments or perform their obligations to us.

The following customers individually represented greater than 10% of our consolidated revenues for the years ended December 31, 2023, 2022, or 2021. No other customers represented greater than 10% of our consolidated revenues during the periods presented.

	Year Ended December 31,		
	2023	2022	2021
Dow Hydrocarbons and Resources LLC	10.4 %	14.2 %	14.5 %
Marathon Petroleum Corporation	19.3 %	14.7 %	13.4 %

Regulation

Recent Regulatory Developments. On January 20, 2021, the Acting Secretary for the Department of the Interior ("DOI") signed an order suspending new fossil fuel leasing and permitting on federal lands, including offshore pipeline leases, 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. Several states filed lawsuits challenging the suspension and on June 15, 2021, a judge in the U.S. District Court for the Western District of Louisiana issued a nationwide temporary injunction blocking the suspension. The Department of the Interior appealed the U.S. District Court's ruling but resumed oil and gas leasing pending resolution of the appeal. In November 2021, the Department of the Interior completed its review and issued a report on the federal oil and gas leasing program. The Department of the Interior's report recommends several changes to federal leasing practices, including changes to royalty payments, bidding, and bonding requirements. In July 2023, the DOI proposed updates to its onshore oil and gas leasing regulations which could further restrict oil and gas exploration and production on federal lands. The DOI expects to issue a final rule in the spring of 2024. These changes and uncertainties could have a negative effect on exploration and production of oil and natural gas and, consequently, negatively impact the demand for our products and services.

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 potential change to the federal leasing program 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 operations, or cash flows, including our ability to make cash distributions to our unitholders.

Natural Gas Pipeline and Storage 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 of 1938 ("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.

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 gives FERC authority to impose civil penalties for violations of these statutes, which has been adjusted to approximately $1.5 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 and storage facilities provide interstate services and, thus, the rates, terms and conditions of such services are subject to FERC jurisdiction under Section 311 of the Natural Gas Policy Act of 1978 ("NGPA"). Under Section 311, along with FERC's implementing regulations, an intrastate pipeline may transport natural gas "on behalf of" an interstate pipeline company or any local distribution company served by an interstate pipeline, without becoming subject to FERC's broader regulatory authority under the NGA. Pipelines providing transportation service under Section 311 of the NGPA 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. We have market-based rates for our Section 311 storage facilities.

In addition to regulation under Section 311 of the NGPA, 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. On December 17, 2020, for the five-year period beginning on July 1, 2021, FERC established an annual index adjustment equal to the change in the producer price index for finished goods plus 0.78%. On January 20, 2022, however, FERC issued an Order on Rehearing revising the annual index adjustment to the change in the producer price index for finished goods minus 0.21% ("Order on Rehearing"). As a result of the change in the index adjustment, certain ceiling levels for our interstate liquids pipelines were reduced and any rates that exceeded the newly computed ceiling levels were subsequently lowered to bring those rates into compliance with the revised ceiling level. The revised rates became effective March 1, 2022. The appropriate index for the five-year period beginning on July 1, 2021 is pending on appeal before the U.S. District Court of the District of Columbia Circuit.

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 (no such exemption exists under the ICA for pipelines transporting liquids in interstate commerce). 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. The U.S. Department of Transportation's Pipeline and Hazardous Materials Safety Administration ("PHMSA") regulates safety issues related to downhole facilities located at both intrastate and interstate underground natural gas storage facilities. PHMSA mandates certain reporting requirements for operators of underground natural gas storage facilities and sets minimum federal safety standards. In addition, all intrastate transportation related underground natural gas storage facilities are subject to minimum federal safety standards and are 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. We believe we are in substantial compliance with these PHMSA rules.

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 natural 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, and we believe we are in substantial compliance with these newer regulations.

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 we are in substantial compliance with these OSHA requirements.

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 natural 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 that govern many aspects of the pipeline life cycle and safety, including regulations that govern the design of pipelines, integrity management programs, leak detection and repair requirements, notification of accidents and incidents and emergency response protocols.

In May 2023, PHMSA proposed a new rule updating the requirements for natural gas pipeline leak detection and repair. The proposed rule includes several updates that would enhance leak survey and patrol requirements, require operators to identify and repair leaks, and expand release reporting. In September 2023, PHMSA issued a proposed rule applicable to natural gas transmission and distribution and gathering pipelines, which would require updates to emergency response plans and other safety practices.

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 on climate change. As part of rejoining the Paris Agreement, the Biden Administration announced that the United States would commit to a 50 to 52 percent reduction from 2005 levels of GHG emissions by 2030, and set the goal of reaching net-zero GHG emissions by 2050. In addition, the EPA recently announced new rules that regulate greenhouse gases, such as methane, and limit emissions in oil and natural gas production, transmission and storage facilities, some of which may require us to make changes to our operations. For instance, the Inflation Reduction Act, passed in August 2022, contains a provision requiring us to pay a fee for our methane emissions that are determined to be in excess of a statutory limit, while the Energy Department has announced it is pausing decisions on applications for new LNG export projects until the parameters for analyzing the projects are completed. The Biden Administration 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 gathering, processing, fractionation, pipeline transmission, and related services for hydrocarbons, including natural gas, NGLs, crude oil, and condensates. 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 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 processing 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. The attainment date for serious nonattainment areas was July 20, 2021, with a 2020 attainment year. The DFW area did not comply with the 2008 ozone NAAQS by the end of 2020. On October 7, 2022, the EPA reclassified the DFW nonattainment area from serious to severe for the 2008 eight-hour ozone NAAQS, effective November 7, 2022. Under a severe classification, the DFW area is required to attain the 2008 eight-hour ozone standard by the end of 2026 to meet a July 20, 2027 attainment date. The severe classification 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.

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, the EPA designated the DFW area, including Wise County, as a marginal nonattainment area under this standard. The DFW Area, however, failed to attain this standard by its marginal attainment date of August 2021. On October 7, 2022 the EPA reclassified the DFW nonattainment area from marginal to moderate for the 2015 eight-hour ozone NAAQS, effective November 7, 2022. Under a moderate classification, the DFW area is required to attain the 2015 eight-hour ozone standard by the end of 2023 to meet an August 3, 2024 attainment date. Furthermore, the area remains subject to the requirements associated with its severe classification under the 2008 standard notwithstanding its moderate 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 the 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.

The EPA reviewed the 2015 NAAQS in 2020 but decided to retain the standard without revision. However, in August 2021, the EPA announced that it intends to reconsider the 2020 decision to retain the 2015 NAAQS. In August 2023, the EPA announced that it will forgo its reconsideration of the 2020 ozone NAAQS in favor of a new, lengthier review of the ozone NAAQS and underlying air quality criteria. To the extent that the EPA's review results in a new standard, the new standard could cause stricter permitting requirements, delays or prohibitions on 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 severe classification under the 2008 standard notwithstanding its moderate classification under the 2015 standard.

In 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 NSPS and NESHAPs programs. These rules required 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 volatile organic compound ("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, the 2020 Policy Rule and the 2020 Technical Amendments. The 2020 Policy Rule 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. 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 the 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, and on June 30, 2021, President Biden signed a joint congressional resolution rescinding the 2020 Policy rule. In December 2023, the EPA issued a new rule targeting methane and VOC emissions from new and existing oil and gas sources, including sources in the production, processing, transmission, and storage segments. The rule: (1) updates NSPS subpart OOOOa; (2) adopts a new NSPS subpart OOOOb for sources that commence construction, modification, or reconstruction after December 6, 2022; and (3) adopts a new NSPS subpart OOOOc to establish emissions guidelines that will be used to guide states when establishing methane standards for facilities that were existing sources on or before December 6, 2022 (i.e., any sources not subject to NSPS OOOOb). Several states are pursuing similar measures to regulate emissions of methane from new and existing sources within the oil and natural gas source category. In addition, in January 2023, the EPA announced a proposed consent decree that, if finalized as proposed, would establish a December 10, 2024 deadline for the EPA to review and propose revisions to the NESHAP for oil and natural gas production facilities and natural gas transmission and storage facilities, which may require us to make additional changes to our operations. Promulgation of increasingly stringent requirements, such as those listed above, or the application of new requirements to existing facilities, could result in additional restrictions on operations and increased compliance costs for us or our customers. The Company had previously complied with many of these regulations during the Obama administration and does not expect the reinstatement to have a material effect on the Company or its operations.

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. Associated EPA guidance clarifies 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 rules in January 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 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. In December 2020, environmental groups appealed the October 2020 decision, and litigation is ongoing. As a result of this continued regulatory focus and other factors, additional GHG regulation of the oil and gas industry remains possible. For example, the Inflation Reduction Act, which was enacted on August 16, 2022, contains a suite of provisions addressing onshore and offshore oil and gas development under federal leases. Under the authority of the Inflation Reduction Act, on November 30, 2022, BLM proposed new regulations to reduce the waste of natural gas from venting, flaring, and leaks during oil and gas production activities on federal and Indian leases, but the final rule has not yet been issued, though it remains on the agency's Unified Agenda. On December 2, 2023, the EPA published a final rule to reduce methane and volatile organic chemicals emissions from the oil and natural gas sector, which strengthens and expands the EPA's December 23, 2023 revisions to the NSPS program. Also, on November 17, 2023, the EPA issued a final rule that enables states to implement more stringent methane emissions standards than the federal guidelines require, which some states have already begun to do. For example, in July 2023, LDNR issued a proposed rule that would restrict routine venting and flaring of methane from oil and natural gas production facilities in the state. 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 formally re-joined the Paris Agreement on February 19, 2021. As part of rejoining the Paris Agreement, President Biden announced that the United States commits to a 50 to 52 percent reduction from 2005 levels of GHG emissions by 2030 and set the goal of reaching net-zero GHG emissions by 2050. On December 13, 2023, the 28th annual United Nations Climate Change Conference ("COP 28"), which was held in Dubai, issued its first global stocktake, which calls on parties, including the United States, to contribute to the transitioning away from fossil fuels, reduce methane emissions, and increase renewable energy capacity, among other things, to achieve net zero emissions by

2050. Legislation to regulate GHG emissions has periodically been introduced in the United States Congress, and such legislation may be proposed or adopted in the future. There has been a wide-ranging policy debate regarding the impact of these gases and possible means for their regulation. Some of the proposals would require industries to meet stringent new standards that would require substantial reductions in carbon emissions. 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. However, the adoption and implementation of any international, federal or state legislation or regulations that restrict emissions of GHGs could result in increased compliance costs or additional operating restrictions.

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.

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 September 2015, a rule issued by the EPA and U.S. Army Corps of Engineers (“USACE”) to revise the definition of “waters of the United States” (“WOTUS”) for all Clean Water Act programs, thereby defining the scope of the EPA’s and the Corps’ jurisdiction, became effective. The EPA rescinded this rule in 2019 and promulgated the Navigable Waters Protection Rule (the “NWPR”) in 2020. The NWPR was viewed as narrowing the scope of WOTUS as compared to the 2015 rule. In August 2021, the U.S. District Court for the District of Arizona vacated and remanded the NWPR. On January 18, 2023, the EPA and USACE jointly issued a final rule revising the definition of WOTUS that largely returns to the pre-2015 regulatory regime. The rule became effective on March 20, 2023. On September 8, 2023, the U.S. Supreme Court issued a decision limiting the scope of federal jurisdiction over wetlands only to those that have a continuous surface connection to water bodies. On August 29, 2023, the EPA and the Corps jointly issued a final rule, which took effect immediately, aligning the regulatory definition of WOTUS with the Supreme Court’s ruling. Because the final rule expands federal jurisdiction as compared to the April 2020 final rule, 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. 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. Additionally, 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. 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 natural 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. In December 2017, BLM published a final rule regarding well stimulation, chemical disclosures, water management, and other requirements for hydraulic fracturing on federal and American Indian lands. This final rule was challenged in the U.S. District Court for the Northern District of California almost immediately after issuance and the case now is pending appeal in the U.S. Court of Appeals for the Ninth Circuit. Reinstatement of the 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.

Human Capital

As of December 31, 2023, we (through our subsidiaries) employed 1,072 full-time employees. Of these employees, 279 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 seek to provide a working environment that empowers our employees, allows them to execute at their highest potential, keeps them safe, and promotes their professional growth. We offer a competitive total rewards program to our employees. Our total rewards program is comprised of base salary, short and long-term incentives tied to our performance, comprehensive employee benefits that include medical and dental coverage, company-paid life insurance, disability coverage, and paid parental leave for both birth and non-birth parents. We also offer a 401(k) program, which includes fully-vested employer matched contributions. We believe that our values, rewarding work environment, and competitive pay help us retain our employees and minimize employee turnover in a very challenging personnel market. Our employees have an average tenure of approximately eight years and voluntary turnover rates for 2023 were approximately 9%.

The safety of our employees is a key management priority. We strive to promote a safety-centric culture, including linking a portion of short-term incentive compensation for our employees to our safety standards and performance. We also maintain strict safety protocols and require quarterly safety training for all field employees and annual safety training for corporate employees. We assess the effectiveness of our safety record by closely monitoring various measures, including our Total Recordable Incident Rate ("TRIR"), which is an industry standard measurement of safety. In 2023, we had a TRIR of 0.57. During 2023, our employees completed approximately 32,000 online and classroom courses comprising approximately 27,000 hours, of which over 10,000 were required safety training.

We also see value in having a diverse and inclusive environment. We have a Diversity, Equity, and Inclusion Action Team, which is responsible for helping us to promote and foster a welcoming, open, and diverse workplace, and whose members are drawn from throughout the company. As of December 31, 2023, women represented approximately 36% of the positions at our corporate offices in Dallas and Houston and held approximately 28% of all manager and above positions (excluding officers) in those offices. At the same date, minorities represented approximately 24% of the manager and above positions at our corporate offices in Dallas and Houston and held approximately 20% of all manager and above positions (excluding officers) company-wide. Additionally, women and minorities constituted approximately 31% of all officers company-wide. We also require annual anti-harassment and discrimination training for all employees, and, in 2023, all personnel managers completed an additional training in support of our diversity and inclusion efforts.

Sustainability

We strive for sustainable business practices, including safe, responsible and ethical operations that respect the environment, support the communities where we operate, care for our employees, and deliver value to our unitholders. We seek to operate our assets safely by focusing on mitigating risk, routinely increasing knowledge and skills of our employees, improving our processes, and measuring our performance. We link a portion of short-term incentive compensation for our employees to our environmental and safety performance in order to promote a culture focused on safety and sustainability. We also strive to operate our existing assets and construct new assets in a way that minimizes our footprint and environmental impact, controls emissions, and conserves resources. We focus on improving our reliability and sustainability through innovation, operational excellence initiatives, and continuous improvement processes. We support our employees by providing competitive pay and benefits, training, and a respectful and inclusive culture.

We have a standing Sustainability Committee ("Sustainability Committee") of the Board, which assists the Board in its general oversight of our environmental, social, and governance initiatives, including our environmental, health and safety, and operational excellence initiatives, and also provides oversight with respect to identifying, evaluating, and monitoring of risks associated with such matters. We have also formed executive sponsored, cross-functional committees that are focused on emissions reductions, sustainability reporting and diversity and inclusion. Each of these working groups are comprised of leaders from various departments of our company and are charged with developing and putting into action our sustainable business practices. EnLink publishes an annual sustainability report, which provides both accountability and transparency regarding our sustainable business practices and progress toward becoming a more sustainable company. Our most recent sustainability report can be found on our sustainability website (http://sustainability.enlink.com). Information included in our Sustainability Report or otherwise included on our website is not incorporated into this Annual Report on Form 10-K.

Environmental Responsibility

We strive for safe operations that minimize our environmental impact. We demonstrate that objective by working to comply 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 strive to operate our assets in a way that maximizes their usefulness, reliability, and safe operations, including using in-line inspection tools, pressure testing, cathodic protection, and corrosion management. We utilize 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 provide safety training for 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, reducing the need to purchase power from the public utility grid. 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 and we continue to make similar changes to our operations, from time to time, to minimize our environmental impact.

We strive to reuse our resources to limit our waste production. We focus on repurposing idle materials and equipment to be used 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 environmental impacts from construction of our facilities. We first identify site options during the project planning phase to avoid wetlands, wildlife 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.

We seek to minimize methane and CO_2 emissions in our operations. We continue to identify and execute projects across our assets to install air compressors for supply to our pneumatic controllers, eliminating waste methane emissions from gas driven pneumatic controllers. In November 2023, we began separating CO_2 from lean natural gas in our North Texas gathering systems and from rich natural gas delivered to our natural gas processing plant in Bridgeport, Texas. This CO_2 waste stream is then captured, compressed, transported, and sequestered by BKV.

Social Responsibility

We provide our employees with a rewarding work environment, providing a platform for personal and professional development. We focus on providing a work environment that provides the tools, resources, and guidance needed to promote personal and professional development. We also strive to create a culture of inclusivity and tolerance at EnLink, led by company leadership, Human Resources, and EnLink's employee-driven Diversity, Equity, and Inclusion Action Team.

EnLink's commitment to social responsibility also includes our commitment to safety, economic development, and employee volunteerism. We support local first responders and nonprofits through community donations and often participate in community events throughout our area of operations each year. Employees are encouraged 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. For more information on our employee initiatives, see "Item 1. Business—Human Capital" in this report.

Governance

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 Board and by the Governance and Compensation Committee (the "Compensation Committee") of the Board. 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 a large portion of the short-term and long-term compensation of our executives to the performance of the company.

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, compliance, 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 and its committees, including the Sustainability Committee and the Audit Committee.

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

- GIP owns approximately 46.1% of our outstanding common units as of February 14, 2024and 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 also may compete with us.
- we are a "controlled company" under NYSE rules and rely on exemptions from certain listing requirements.

- our operating agreement replaces fiduciary duties otherwise owed to our unitholders with limited contractual standards, restricts remedies available to our unitholders for actions of the Managing Member, and restricts the voting rights of unitholders owning 20% or more of ENLC's common units;
- unitholders have limited voting rights and are not entitled to elect or remove the Managing Member or its directors without the Managing Member's consent;
- GIP may sell common units, and a default under GIP's credit facility or a change in control of GIP could result in a change in control and a default or prepayment event under some of our debt agreements;
- 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 Series B Preferred Units may be exchanged for our common units, diluting common unitholders;
- 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;
- our Managing Member has a call right that may require unitholders to sell their common units at an undesirable time or price;
- costs reimbursements due to the Managing Member and its affiliates will be determined by the Managing Member and could be substantial;
- unitholders may have liability to repay distributions that were wrongfully distributed to them; and
- the price of our common units may fluctuate significantly.

Financial and Indebtedness 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 and 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 long-lived assets, lease right-of-use 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 raise our cost of borrowing and 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 tax laws or policies may result in adjustments to the judgments and estimates we use in the determination of tax-related asset and liability amounts, as well as the probability of recognition of income, deductions and tax credits.

Business and Industry Risks

- 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;
- our inability to retain existing customers or acquire new customers would reduce our revenues and limit our future profitability;
- 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;
- sustained geopolitical conflicts, military action and civil unrest could result in disruptions to the global supply chain and uncertain economic conditions;
- 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;

- vulnerability to weather-related risks could adversely impact our financial condition, results of operations, or cash flows;
- our dependency on certain of our large customers 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;
- future growth may be limited if we are unable to make acquisitions on economically acceptable terms and integrate assets into our asset base effectively;
- failure to successfully build or enter our new CCS transportation business or entering into new other businesses could limit our future growth if we are unable to execute on our strategy or operate these new lines of business effectively;
- the construction of new midstream assets and major development projects involves many risks and could negatively affect our financial position, results of operations, cash flows and future growth if we are unable to execute and manage these projects successfully;
- 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;
- 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;
- our use of derivative financial instruments does not eliminate our exposure to commodity price fluctuations and could result in financial losses or reduce our income; and
- terrorist or cyberattack or a failure of our computer systems, or third parties with whom we have a relationship, may adversely affect our ability to operate our business and may harm our reputation.

Environmental, Legal Compliance, and Regulatory Risks

- increases in federal, state, and local legislation, and regulatory initiatives, as well as government reviews relating to hydraulic fracturing 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 could impact our operations;
- federal and state rate and service regulation and pipeline safety regulation on our natural gas or liquids pipelines could limit our revenues and 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; and
- compliance with privacy and data protection laws could increase our operating costs.

Risks Inherent in an Investment in ENLC

GIP owns approximately 46.1% of ENLC's outstanding common units as of February 14, 2024 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 voting power, 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 the level of our distributions. 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.

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.

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, 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, 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 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.

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, cannot vote on any matter.

Holders of ENLC common units have limited voting rights and are not entitled to elect the Managing Member or the Board, 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 on an annual or other continuing basis. The Board, 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 14, 2024, the Managing Member and its affiliates owned approximately 46.1% 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 in control of the Managing Member, which would permit the lenders under certain of ENLC's debt agreements to declare all amounts thereunder due and payable, and it could result in a prepayment event under some of our debt agreements.

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 GIP's purchase of equity interests in ENLK, ENLC, and the Managing Member from certain subsidiaries of Devon in 2018 (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 in 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. On January 12, 2024, GIP announced that it entered into an agreement with BlackRock, Inc. pursuant to which BlackRock would acquire GIP for cash and stock consideration. GIP indicated that the transaction is expected to close in the third quarter of 2024 subject to customary regulatory approvals and other closing conditions. The consummation of the transaction may result in a change in control under the GIP Credit Facility, unless GIP obtains the consent of the lenders under, or otherwise amends, the GIP Credit Facility to permit such transaction. Moreover, any change in control of the Managing Member, which would occur upon a change of control of GIP, would permit the lenders under some of our debt agreements to declare all amounts thereunder immediately due and payable and would potentially result in prepayment events under some of our debt agreements. 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. There can be no assurance that, if the GIP transaction results in a change in control of the Managing Member, we would be able to receive the consent of the lenders under, or otherwise amend, ENLC's Revolving Credit Facility or AR Facility, to permit such change in control.

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 in control" of the Managing Member without the vote or consent of the unitholders. On July 18, 2018, certain subsidiaries of Devon sold their equity interests in the Managing Member to affiliates of GIP without a vote or consent of the ENLC unitholders. For more information on this transaction, see "Item 8. Financial Statements and Supplementary Data—Note 1" of our Annual Report on Form 10-K for the fiscal year ended December 31, 2021, filed with the Commission on February 16, 2022, and available here.

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. 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 holders of ENLK's Series B Preferred Units may exchange such units into ENLC common units, which could cause dilution to our common unitholders. Such holders may sell such common units in the public markets or otherwise, which sales could have a material adverse impact on the trading price of our common units.

The exchange of ENLK's Series B Preferred Units into common units, which the holders of the Series B Preferred Units may elect to cause at any time, may cause substantial dilution to the holders of the common units. The Series B Preferred Units are exchangeable into a number of common units equal to the number of Series B Preferred Units being exchanged multiplied by 1.15 (subject to certain adjustments). As of February 14, 2024, on an as-exchanged basis, the Series B Preferred Units represented approximately 12.2% of the membership interests of ENLC. We have provided the holders of the Series B Preferred Units with certain registration rights with respect to the ENLC common units to be issued in exchange for the Series B Preferred Units, and we have filed a registration statement on Form S-3 to cover registered sales of ENLC common units by such holders. The sale of these common units could have a material adverse impact on the price of ENLC common units.

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 14, 2024, GIP held 208,765,211 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 a material adverse impact on the price of ENLC common units or on any trading market that may develop. During 2022 and 2023, we entered into agreements with GIP pursuant to which we agreed to repurchase, on a quarterly basis, a pro rata portion of the ENLC common units held by GIP, based upon the number of common units purchased by us during the applicable quarter from public unitholders under our common unit repurchase program. Under these agreements, the number of ENLC common units held by GIP that we repurchased in any quarter is calculated such that GIP's then-existing economic ownership percentage of our outstanding common units is maintained after our repurchases of common units from public unitholders are taken into account, and the per unit price we paid to GIP is the average per unit price paid by us for the common units repurchased from public unitholders, less broker commissions, which are not paid with respect to the GIP units. On January 16, 2024, we entered into a repurchase agreement with GIP for 2024 on terms substantially similar to those agreements entered into in respect of 2022 and 2023. See “Item 8. Financial Statements and Supplementary Data—Note 5 and Note 10” for more information regarding repurchases of ENLC common units held by GIP.

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 14, 2024, GIP owned an aggregate of approximately 46.1% of outstanding ENLC common units.

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.

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 14, 2024, approximately 53.9% 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 a key customer;
- 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 or the impact of any future pandemic;
- 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.”

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 Revolving 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 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;
- 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 operational 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 Revolving Credit Facility, the AR Facility, and indentures governing our senior unsecured notes and ENLK’s senior unsecured notes may restrict our current and future operations, particularly our ability to respond to changes in business or to take certain actions.

The Revolving Credit Facility, the AR Facility, and the indentures governing our senior unsecured notes and ENLK’s senior unsecured 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.

Unless waived or otherwise agreed by the requisite lenders under ENLC's debt agreements, a change in control (as defined in the applicable debt agreement) of ENLC would result in an event of default under the Revolving Credit Facility and the AR Facility, and such event could result in a prepayment event under other debt agreements.

In addition, the Revolving Credit Facility and the AR Facility require ENLC's consolidated net leverage ratio not to exceed a specified limit. 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 our debt agreements. 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 14, 2024, Fitch Ratings, S&P, and Moody's have assigned a BBB-, BB+, and Ba1 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. We recognized impairment expense related to property and equipment as follows (in millions):

	Year Ended December 31,		
	2023	2022	2021
Property and equipment impairment (1)	$ 20.7	$ —	$ 0.6

(1) During the third quarter of 2023, we identified changes in our outlook for future cash flows and the anticipated use of certain ORV crude assets in our Louisiana segment. We determined that the carrying amounts of these assets exceeded their fair values, based on market inputs and certain assumptions.

Additional impairments 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. If commodity prices were to decline, as they have in regular cycles in the past, 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.

Increases in interest rates would raise ENLC's cost of borrowing and 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 rose significantly during 2022 and 2023 as the Federal Reserve sought to control inflation. Our Revolving Credit Facility and our AR Facility have floating rates tied to SOFR or other interest rate benchmarks that generally rise alongside the increase in the federal funds rate. As a result, interest costs on our existing floating rate debt rose during 2022 and 2023 and, except to the extent we enter into hedging or other interest rate management agreements, would likely rise further if interest rates continue to rise. In addition, 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 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. Beginning with the interest period commencing on December 15, 2022, distributions on ENLK's Series C Preferred Units have been based on a floating rate tied to LIBOR rather than a fixed rate. As a result of the floating rate, the amount paid by ENLK for distributions became more sensitive to changes in interest rates. Starting on September 15, 2023, distributions on the Series C Preferred Units have been based on the forward-looking term rate based on SOFR ("Term SOFR").

We may not realize our deferred tax assets.

As of December 31, 2023, we had deferred tax assets (primarily consisting of federal and state net operating loss carryovers) of $759.5 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.

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 certain other 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 unitholders (or groups of unitholders) that are each deemed to own at least 5% of our common units increase their ownership by more than 50 percentage points over their lowest ownership percentage during a rolling three-year period. As of December 31, 2023, 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 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.

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. In the event we do generate taxable income, federal and state income tax liabilities will reduce the cash available for distribution to our unitholders.

Changes in tax laws or policies, including but not limited to changes in corporate income tax rates, as well as judgments and estimates used in the determination of tax-related asset and liability amounts, could materially adversely affect our business, financial condition, results of operations and prospects.

Our provision for income taxes and reporting of tax-related assets and liabilities requires judgments and the use of estimates. Amounts of tax-related assets and liabilities involve judgments and estimates of the timing and probability of recognition of income, deductions and tax credits, including, but not limited to, estimates for potential adverse outcomes regarding tax positions that have been taken and the ability to utilize tax benefit carryforwards, such as net operating loss and tax credit carryforwards. Actual income taxes could vary significantly from estimated amounts due to the future impacts of, among other things, changes in tax laws, guidance or policies, including changes in corporate income tax rates and the resolution of audit issues raised by taxing authorities. These factors, including the ultimate resolution of income tax matters, may result in material adjustments to tax-related assets and liabilities, which could materially adversely affect our business, financial condition, results of operations and prospects.

The Inflation Reduction Act of 2022 or IRA, which was enacted on August 16, 2022 contains a number of revisions to the Internal Revenue Code, including (i) a 15% corporate minimum income tax for certain taxpayers with average annual book income of $1 billion or more, (ii) a 1% excise tax on corporate stock repurchases and (ii) expanded business tax credits and incentives for the development of clean energy and carbon capture projects and the production of clean energy. We do not expect that these provisions will have a material impact on our consolidated financial statements or financial condition.

Business and Industry Risks

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, including the impact of hurricanes and winter storms;
- 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 natural gas, NGL, crude oil, and condensate sales commitments that we satisfy through supplies purchased under long-term natural 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 natural 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. 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 natural gas processing and NGL fractionation components of our business. 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. 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 natural 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.

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, 2023, approximately 10% 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, processing margin contracts, and NGL product upgrades.

Commodity prices were volatile during 2023. Crude oil prices decreased 11%, weighted average NGL prices decreased 21%, and natural gas prices decreased 44% from January 1, 2023 to December 31, 2023. The table below shows the range of closing prices for crude oil, NGL, and natural gas during 2023.

Commodity	Closing Price		Date
Crude oil (high) (1)	$	93.68	September 27, 2023
Crude oil (low) (1)	$	66.74	March 17, 2023
Crude oil (average) (1)(4)	$	77.60	—
NGL (high) (2)	$	0.69	January 19, 2023
NGL (low) (2)	$	0.34	June 12, 2023
NGL (average) (2)(4)	$	0.50	—
Natural gas (high) (3)	$	4.17	January 4, 2023
Natural gas (low) (3)	$	1.99	March 29, 2023
Natural gas (average) (3)(4)	$	2.66	—

(1) Crude oil closing prices based on the NYMEX futures daily close prices.
(2) Weighted average NGL 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 natural gas producing nations;
- the continued threat of terrorism and the actual or potential disruptions to supply chains from geopolitical conflicts, military action and civil unrest;
- public health crises or pandemics that reduce economic activity and affect the demand for travel;
- 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 natural 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.

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 natural 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.

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 natural 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.

Sustained geopolitical conflicts, military action and civil unrest could result in disruptions to the global supply chain and uncertain economic conditions, which could materially adversely affect our financial condition, results of operations, or cash flows, as well as heighten a number of the risk factors discussed in this report.

U.S. and global markets experienced volatility and disruption following the military conflicts between Ukraine and Russia and conflicts in the Middle East. In addition, the United States, Canada, the European Union, and other countries have levied economic sanctions and other penalties on Russia, Belarus, the Crimea Region of Ukraine, the so-called Donetsk People's Republic, and the so-called Luhansk People's Republic, such as, the agreement by the United States and the European Union to remove certain Russian financial institutions from the Society for Worldwide Interbank Financial Telecommunication (SWIFT) payment system. Although the length and full impact of these ongoing conflicts remains uncertain, the events in Ukraine have resulted in widespread market disruptions, including significant volatility in commodity prices, credit, and capital markets and the events in the Middle East could result in similar affects. The broader consequences of these conflicts, which may include further sanctions, embargoes, regional instability, geopolitical shifts, transportation bans on or avoidance of certain shipping routes, could adversely affect global economic conditions and financial markets. This may lead to economic instability, sustained inflation and changes in liquidity and credit availability. Any of the factors described above could materially and adversely affect our business, financial condition, results of operations, or cash flows. Furthermore, a protracted geopolitical conflict could heighten the frequency and severity of certain of the risks discussed in this section, and significantly impact our operations. For example, some companies have reported an increase in cybersecurity threats attributable to state actors and individuals sympathetic to the warring parties, some of which are directed at energy enterprises and their respective third party vendors.

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 could also face pressures from stakeholders, who are increasingly focused on climate change, to prioritize sustainable energy practices, reduce our carbon footprint and promote sustainability. These stakeholders could require us to implement ESG procedures or standards in order to remain invested in us or before they could make further investments in us. Additionally, we could face reputational challenges in the event our ESG procedures or standards do not meet the standards set by certain constituencies. In addition, organizations that provide information to investors on corporate governance and related matters have developed ratings processes for evaluating companies on their approach to ESG matters. Unfavorable ESG ratings may lead to increased negative investor sentiment toward us or our customers and to the diversion of investment to other industries which could have a negative impact on our unit price and/or our access to and costs of capital. We have adopted certain practices as highlighted in our annual sustainability report, including a focus on 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 stakeholder 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 global, national, and various state social and political environments, 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.

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, extreme cold weather, fires, severe temperatures, and earthquakes, and also disruptions caused by these natural events, such as electrical blackouts. In particular, South Louisiana and the Texas Gulf Coast experience hurricanes and other extreme weather conditions on a frequent basis. The location of significant assets and concentration of activity in these regions make us particularly vulnerable to weather risks in these areas.

During 2020 and 2021, our Louisiana operations were affected by hurricanes, resulting in a temporary loss of some processing volumes or a temporary shut-down of some of our operations and those of our downstream customers. The location of significant assets and concentration of activity in active hurricane regions make us particularly vulnerable to weather events in these areas.

In addition, our assets are vulnerable to winter storms and extreme cold weather. For example, in February 2021, the areas in which we operate experienced a severe winter storm, with extreme cold, ice, and snow occurring over an unprecedented period of approximately 10 days ("Winter Storm Uri"). Winter Storm Uri adversely affected our facilities and activities across our footprint, as it did for producers and other midstream companies located in these areas. The severe cold temperatures caused production freeze-offs and also led some producers to proactively shut-in their wells to preserve well integrity. As a result, our gathering and processing volumes were significantly reduced during this period, with peak volume declines ranging between 44% and 92%, depending on the region. In December 2022, we again experienced a severe winter storm ("Winter Storm Elliot") and in January 2024 there was a prolonged period of very cold weather in the Southern Plains area in which we operate. Although these events were not as severe or as long lasting as Winter Storm Uri, our operations were affected during these periods, particularly in the Permian and in Oklahoma.

High winds, storm surge, flooding, ice storms, extreme cold weather, and other natural disasters can cause significant damage and curtail our operations for extended periods during and after such weather conditions and could cause significant disruptions in electrical power, all of 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. Moreover, as a larger portion of our operations become dependent on a steady supply of electric power to operate, in part as a result of a shift to electrical power in order to minimize CO_2 emissions, we would be more vulnerable to events such as extreme weather that cause blackouts, which could disrupt our operations and persist for a significant period of time.

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 and persistent electrical blackouts 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. Also, disruptions in our operations, which affect our customers and other third parties, have generated, and could in the future generate, commercial and legal disputes with these parties that could cause us to pay damages or make business concessions to these parties, and these damages or business concessions might be costly to the Company and adversely affect our financial condition, results of operation, and cash flows. For example, as a result of Winter Storm Uri in February 2021, we encountered customer billing disputes related to the delivery of natural gas during the storm, including one that resulted in litigation given our declaration of force majeure. See "Item 8. Financial Statements and Supplementary Data—Note 15" for more information on litigation proceedings and contingencies.

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 operations, or cash flows.

We are dependent on certain large customers for a substantial portion of the natural gas that we gather, process, and transport. The loss of any of these customers would adversely affect our financial condition, results of operations, or cash flows.

We are dependent on certain large customers for a substantial portion of our natural gas supply, including those customers described under 'Business – Credit Risk and Key Customers." We expect to derive a significant portion of our revenues and adjusted gross margin from those customers 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.

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 are building a new business providing CCS transportation services and we may enter into other new businesses in connection with our strategy to participate in the energy transition. If we are unable to execute on this strategy or operate these new lines of business effectively, our future growth could be limited. These new lines of business may never develop or may present risks that we cannot effectively manage.

As part of our strategy, we are building a carbon transportation business to support CCS activities, and we may enter into other new lines of business as part of adapting to the energy transition. The CCS business and other new lines of business we may engage in are new businesses that have no track record and which, while similar to our existing businesses, may present different challenges and risks. We may be unable to execute on our business plans, demand for these new services may not develop on a large or economic scale, or we may fail to operate these businesses effectively. In addition, we may not be able to compete with companies who also plan to enter into these new lines of business, and who may be larger than us and may have greater financial resources to devote to these businesses. These new businesses may also present novel issues in law, taxation, safety or environmental policy, and other areas that we may not be able to manage effectively. Management's assessment of the risks in these new lines of business may be inexact and not identify or resolve all the problems that we could face. If we were not able to manage our new CCS business or any of the other new lines of business effectively or at all, it could limit our future growth as lines of business connected to the energy transition grow and become a more important part of the energy business. In October 2022, we entered into a transportation services agreement with a subsidiary of ExxonMobil in connection with the development of a CCS project in the Mississippi River corridor in southeastern Louisiana. Under the transportation agreement, we contracted to deliver CO_2 from the Mississippi River corridor to ExxonMobil's storage location at Pecan Island in

Vermilion Parish, Louisiana, beginning in 2025. In February 2024, we announced that we and ExxonMobil have agreed to reassess the Pecan Island project's near-term role, with the expectation that other joint CCS opportunities along the Gulf Coast, and beyond the Mississippi River corridor, may be prioritized ahead of the Pecan Island project. If we were not able to agree with ExxonMobil on these alternative CCS opportunities, the future growth of our CCS business could be impacted.

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

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

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

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

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, and crude oil, 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, farm equipment, or operations on adjacent properties;
- leaks of natural gas, NGLs, crude oil, condensate, and other hydrocarbons;
- induced seismicity;
- 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. In addition, certain of our joint venture arrangements provide our joint venture partners with the right, under certain circumstances, to cause us to purchase their interest in the joint venture or to seek to sell the entire joint venture. For example, at any time after June 30, 2025, NGP has the right to cause the Delaware Basin JV to sell all of the outstanding interests or assets of the Delaware Basin JV for the best available price; provided that, if NGP exercises this right, we are permitted to purchase NGP's interest at a certain call price. 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 and facilities, including storage facilities, refineries, and export facilities, owned and operated by unaffiliated third parties. The continuing operation of, and our continuing access to, such third-party pipelines, processing, storage, and export facilities, and other midstream facilities is not within our control. These pipelines, plants, and other midstream facilities may become unavailable because of testing, turnarounds, 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, unplanned incidents, 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 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 our officers 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.

The midstream services we provide require laborers skilled in multiple disciplines, such as equipment operators, mechanics, and engineers, among others, as well as skilled workers in back-office disciplines, such as accounting and internal audit. 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. In addition, it has been widely reported in the press and elsewhere that businesses have faced a more challenging hiring environment in recent years and have had to pay higher wages to attract skilled labor. 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 Revolving Credit Facility and the AR Facility expose us to fluctuations in interest rates. We may use over-the-counter price and basis swaps with other natural gas merchants and financial institutions to manage this risk, which is intended to reduce our exposure to volatility in commodity prices. As of December 31, 2023, 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 increasingly reliant on technology to conduct our business. Our business is dependent upon our operational and financial computer systems and those of our third-party providers with whom we are connected 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. Dependence on automated systems may increase the risks related to operational systems failures and breaches of critical operational or financial controls, and tampering or deliberate manipulation of such systems may result in losses that are difficult to detect.

From time to time, we engage third-party assessors, consultants, auditors, and other specialized service providers as a part of our cybersecurity risk management. While such engagements are aimed at bolstering the effectiveness of our risk management processes, they introduce inherent risks and complexities that warrant careful consideration. Any oversight or failure on the part of these third parties could compromise the security of our sensitive data, proprietary information, and critical business processes, leading to potential data breaches or unauthorized access. Additionally, the reliance on external entities introduces complexities in coordinating risk management efforts, data sharing, and maintaining confidentiality. Any mismanagement or inadequate coordination between our internal teams and third-party vendors could result in delays in responding to cybersecurity threats or gaps in our risk mitigation strategies. Any failure of our or our third-party providers' computer systems, or those of our customers, suppliers, or others with whom we do business, could materially disrupt our ability to operate our business. Some individuals and groups, including criminal organizations and state-sponsored groups, have attempted to gain unauthorized access to computer networks of U.S. businesses and mounted cyberattacks to disable or disrupt computer systems, disrupt operations, and steal funds or data including through phishing schemes, which are attempts to obtain unauthorized access by targeted acts of deception against individuals with legitimate access to physical locations or information. For example, in 2021, a company in the midstream industry suffered a ransomware cyberattack that impacted computerized equipment managing a pipeline and resulted in the halt of the pipeline's operations in order to contain the attack.

Cyberattacks could also result in the loss of confidential or proprietary data or security breaches of other information technology and pipeline systems that could damage our reputation and disrupt our operations and critical business functions and may have a material adverse effect on our business and results of operations. Since the COVID-19 pandemic, we have instituted a part-time work from home policy, so many of our employees and those of our service providers, vendors and customers have been and continue to access computer systems remotely where their cybersecurity protections may be less robust and our cybersecurity procedures and safeguards may be less effective. Our assets may also be targets of vandalism, theft, destructive forms of protests and opposition by extremists, including acts of sabotage and terrorism, that could disrupt our ability to conduct our business and may have a material adverse effect on our business and results of operations. Furthermore the U.S. government has continued to issue public warnings that the nation's strategic infrastructure, such as energy-related assets, may be at greater risk of future terrorist or cyberattacks than other targets in the United States. Any such terrorist or cyberattack that affects us or our customers, suppliers, or others with whom we do business, or that severely disrupts the markets we serve, could have a material adverse effect on our business, cause us to incur a material financial loss, subject us to possible legal claims under federal or state laws and liability, and/or damage our reputation. Our insurance may not protect us against losses relating to such occurrences.

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 and any failure by us to comply with these additional regulations could result in significant penalties and liability to us. 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 natural 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. The EPA and the BLM as well as other federal agencies 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.

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 formally re-joined 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. President Biden declared that he would support federal government efforts to limit or prohibit hydraulic fracturing and ban new leases for production of minerals on federal properties, including onshore lands and offshore waters. In addition, as discussed under "Item 1. Business—Regulation," 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. 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. Several states filed lawsuits challenging the suspension and on June 15, 2021, a federal judge issued a nationwide temporary injunction blocking the suspension. The Department of the Interior appealed the judge's ruling but resumed oil and gas leasing pending resolution of the appeal. In July 2023, the DOI proposed updates to its onshore oil and gas leasing regulations which could further restrict oil and gas exploration and production on federal lands. The DOI expects to issue a final rule in the spring of 2024. All of these changes and uncertainties could have a negative effect on exploration and production of oil and natural gas and, consequently, negatively impact the demand for our products and services. 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.

Over the past few years, the Biden administration has focused on regulating methane emissions in the production of oil and gas, including through venting and flaring. To this end, the EPA, BLM, and other agencies have issued regulations that may require us to make changes to our operations and may require us to pay a fee associated with our methane emissions. Additional regulatory actions targeting methane and other GHG emissions may be put in place in the future. We cannot predict, what effect, if any, such additional actions might have on our operations.

In addition, on January 26, 2024, the Biden Administration announced that it was pausing decisions on applications for new LNG export projects until the Department of Energy is able to adopt new parameters for analyzing the projects. These new parameters would include the review of the economic and environmental effects of new facilities on US climate goals and other factors. While this pause will not affect operating LNG facilities or facilities that have previously secured government approval, it will affect the approval process for future LNG facilities and for expansions of existing facilities. It is uncertain how long the pause will be in place and what changes to the analysis parameters will be adopted. If the pause is in place for an extended period of time or the new parameters adopted result in fewer new LNG projects being built in the future, the growth in LNG exports, which in the past few years has been strong, could be reduced and such reduction could have a negative effect on the price of US natural gas, which, in turn, could have a negative effect on our business and results of operations.

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. Certain municipalities have also proposed or enacted restrictions on the installation of natural gas appliances and infrastructure in new residential or commercial construction, which could affect demand for the natural gas and NGL services we provide. Conversely, some other states and municipalities have initiated legal actions or proposed laws that purport to limit actions taken by companies to address GHG emissions or climate change or to respond to pressure from groups described below that promote such actions.

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 and their regulators, such as the Federal Reserve, 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. Furthermore, recent judicial decisions have allowed certain tort claims brought by government and private plaintiffs alleging property damages due to climate change to proceed against GHG emissions sources, which may increase our litigation risk for such claims. 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. We may be unable to include some or all of such increased costs in the rates charged to our customers and any such recovery may depend on events beyond our control, including the outcome of future rate proceedings before the FERC or state regulatory agencies and the provisions of any final legislation or implementing regulations.

Although it is not possible at this time to predict whether future legislation or new regulations may be adopted to address GHG emissions, including to impose taxes or purchase allowances, 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. Moreover, many scientists have concluded that increasing concentrations of GHGs may produce climate changes associated with an increase in severity and frequency of extreme weather conditions which may affect our operations. See "—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" for more information regarding risks from extreme weather conditions.

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 and store natural gas in our 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 (excluding our Section 311 storage facility with market-based rates). 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 $1.5 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.

The Cajun Sibon pipeline, Avenger crude gathering system, and Greater Chickadee crude gathering system 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, currently pending on appeal before the United States Court of Appeals for the District of Columbia Circuit. 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, which went into effect in July 2020, impose several new requirements on operators of onshore natural gas transmission systems and hazardous liquids pipelines. The rule concerning natural 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. For example, in May 2023, PHMSA proposed a new rule that would enhance leak survey and patrol requirements and require operators to identify and repair leaks. Additionally, in September 2023, PHMSA issued a proposed rule applicable to natural gas transmission and distribution and gathering pipelines, which would require updates to emergency response plans and other safety practices. At this time, we cannot predict the cost of future requirements, but they could be significant. Moreover, violations of pipeline safety regulations can result in the imposition of significant penalties.

Several states have also passed legislation or promulgated rules to address pipeline safety. Compliance with pipeline integrity laws and other pipeline safety regulations issued by state agencies, such as the TRRC, could result in substantial expenditures for testing, repairs, and replacement. For example, TRRC regulations require periodic testing of all intrastate pipelines meeting certain size and location requirements. Our costs relating to compliance with the required testing under the TRRC regulations were approximately $3.1 million, $2.1 million, and $3.2 million for the years ended December 31, 2023, 2022, and 2021, 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, the 2020 Policy Rule and the 2020 Technical Amendments. The 2020 Policy Rule 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. In June 2020, President Biden signed a joint congressional resolution rescinding the 2020 Policy Rule, and in December 2023, the EPA issued a new rule targeting methane and VOC emissions from new and existing oil and gas sources, including sources in the production, processing, transmission, and storage segments. The rule: (1) updates NSPS subpart OOOOa; (2) adopts a new NSPS subpart OOOOb for sources that commence construction, modification, or reconstruction after December 6, 2022; and (3) adopts a new NSPS subpart OOOOc to establish emissions guidelines that will be used to guide states when establishing methane standards for facilities that were existing sources on or before December 6, 2022.

On December 2, 2023, the EPA published a final rule to reduce methane and volatile organic chemicals emissions from the oil and natural gas sector, which strengthens and expands the EPA’s previous revisions to the NSPS program. Also, on November 17, 2023, the EPA issued a final rule that enables states to implement more stringent methane emissions standards than the federal guidelines require, which some states have already begun to do. For example, in July 2023, LDNR issued a proposed rule that would restrict routine venting and flaring of methane from oil and natural gas production facilities in the state. Several other states are also pursuing similar measures to regulate emissions of methane from new and existing sources within the oil and natural gas source category. In addition, in January 2023, the EPA announced a proposed consent decree that, if finalized as proposed, would establish a December 10, 2024 deadline for the EPA to review and propose revisions to the NESHAP for oil and natural gas production facilities and natural gas transmission and storage facilities.

In November 2016, the BLM adopted rules 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 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. Then, in July 2020, the U.S. District Court for the Northern District of California vacated BLM's 2018 revision rule, and in October 2020, a Wyoming federal district judge vacated the 2016 rule. However, in December 2020, environmental groups appealed the October 2020 decision, and litigation is ongoing.

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

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

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

Our business 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 1C. Cybersecurity

We maintain a robust cyber risk management program designed to identify, assess, manage, mitigate, and respond to cybersecurity threats. This program is integrated within the Company's enterprise risk management system and is designed to addresses the corporate information technology environment in which we operate. The underlying controls of the cyber risk management program are based on recognized best practices and standards for cybersecurity and information technology, including the National Institute of Standards and Technology Cybersecurity Framework (“NIST CSF”).

We utilize a third-party cybersecurity operations center to provide 24/7 monitoring of our cybersecurity environment and to coordinate the investigation and remediation of alerts. A program for assisting with incident response is in place to prepare support teams in the event of a significant incident. We also have an annual assessment, performed by a third-party, of our cyber risk management program against the NIST CSF. Cyber partners are a key part of EnLink’s cybersecurity infrastructure. We partner with leading cybersecurity companies and organizations, leveraging third party technology and expertise. EnLink engages with these partners to monitor and maintain the performance and effectiveness of EnLink’s technology environment.

EnLink’s Director of Information Systems reports to EnLink’s Chief Information Officer and is the head of the Company’s cybersecurity team. The Chief Information Officer is responsible for assessing and managing EnLink’s cyber risk management program, informing senior management regarding the prevention, detection, mitigation, and remediation of cybersecurity incidents and supervising such efforts, including overseeing and identifying risks from cybersecurity threats associated with the use of third party cyber security partners. The Chief Information Officer also has a regular quarterly meeting with EnLink’s executive team to review cybersecurity matters and the status of EnLink’s cyber risk management program in detail. The cybersecurity team has decades of experience selecting, deploying, and operating cybersecurity technologies, initiatives, and processes, and relies on threat intelligence as well as other information obtained from governmental, public or private sources, including external consultants engaged by EnLink.

Our Audit Committee oversees EnLink’s cybersecurity risk exposures and the steps taken by management to monitor and mitigate cybersecurity risks. The cybersecurity team briefs the Audit Committee on the status and the effectiveness of EnLink’s cyber risk management program on a quarterly basis and the Board is also updated on cybersecurity issues on a regular basis.

EnLink faces risks from cybersecurity threats that could have a material adverse effect on its business, financial condition, results of operations, cash flows or reputation. We have not been subject to cybersecurity incidents that have materially impaired our operations or had a material adverse effect on EnLink’s business, financial condition or results of operations. For additional discussion of our cybersecurity risks, see “Risk Factors–Business and Industry Risks–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.”

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 rights, 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. We may also be involved in lawsuits with landowners in which a court determines the value to be paid for a pipeline easement or other property right as a result of our exercise of eminent domain or common carrier rights. Except as otherwise set forth herein, under “Item 8. Financial Statements and Supplementary Data—Note 15” 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 15” for more information on litigation proceedings and contingencies.

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 January 31, 2024, there were 30,324 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 Revolving Credit Facility, 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 believes are prudent to maintain.

Purchases of Equity Securities

During the three months ended December 31, 2023, we re-acquired ENLC common units from certain employees in order to satisfy the employees' tax liability in connection with the vesting of unit-based awards and we repurchased common units in open market transactions and from GIP in connection with our 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, 2023 to October 31, 2023	2,503,475	$ 12.01	2,503,475	$ 8.8
November 1, 2023 to November 30, 2023	1,085,499	$ 12.79	1,063,961	$ 45.2
December 1, 2023 to December 31, 2023	2,207,582	$ 12.70	2,207,582	$ 17.2
Total	5,796,556	$ 12.42	5,775,018	

(1) The total number of units purchased shown in the table includes 21,538 ENLC common units received by us from employees for the payment of personal income tax withholding on vesting transactions.

(2) In December 2022, the Board reauthorized our common unit repurchase program for 2023 and set the amount available for repurchases of outstanding common units during 2023 at up to $200.0 million. In November 2023, the Board approved an increase in the common unit repurchase program for 2023 of up to $250.0 million and, in December 2023, set the authorized amount available for repurchases in 2024 to $200.0 million. 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 Exchange Act. The repurchases will depend on market conditions and may be discontinued at any time. For more information regarding common units repurchased from public unitholders and our repurchase of common units held by GIP, see "Item 8. Financial Statements and Supplementary Data—Note 10."

Item 6. [Reserved]

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. Certain items related to the year ended December 31, 2022 and 2021 and year-to-year comparisons of the year ended December 31, 2022 and the year ended December 31, 2021 have been recast to conform to current period presentation, and therefore are shown below. Items that remain unchanged from the discussion in our prior year's Annual Report on Form 10-K 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, 2022.

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 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 owning, operating, investing in, and developing midstream energy infrastructure assets to provide midstream energy services, including:

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

As of December 31, 2023, our midstream energy asset network includes approximately 13,600 miles of pipelines, 25 natural gas processing plants with approximately 5.8 Bcf/d of processing capacity, seven fractionators with approximately 316,300 Bbls/d of fractionation capacity, barge and rail terminals, product storage facilities, purchasing and marketing capabilities, and equity investments in certain joint ventures. We manage and report our operations primarily according to the geography and the nature of the activity. 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 transmission pipelines, natural gas processing plants, natural gas and NGL storage facilities, and fractionation facilities located in Louisiana and, prior to its sale in November 2023, 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 Cana-Woodford, Arkoma-Woodford, northern Oklahoma Woodford, STACK, and adjacent areas;

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

- *Corporate Segment.* The Corporate segment includes our unconsolidated affiliate investments in the Cedar Cove JV in Oklahoma, GCF in South Texas, and the Matterhorn JV in West Texas, as well as our 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 90% of our adjusted gross margin was derived from fee-based contractual arrangements with minimal direct commodity price exposure for the year ended December 31, 2023.

Our revenues and adjusted gross margins are generated from six 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; and
- providing natural gas, crude oil, and NGL storage.

The following customers individually represented greater than 10% of our consolidated revenues for the years ended December 31, 2023, 2022, or 2021. No other customers represented greater than 10% of our consolidated revenues during the periods presented.

	Year Ended December 31,		
	2023	2022	2021
Dow Hydrocarbons and Resources LLC	10.4 %	14.2 %	14.5 %
Marathon Petroleum Corporation	19.3 %	14.7 %	13.4 %

We gather, transport, or store natural gas owned by others under fee-only contract arrangements based either on the volume of natural 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 natural gas sales commitments that we satisfy through supplies purchased under long-term natural 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 natural 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 natural gas was purchased.

We typically buy mixed NGLs from our suppliers to our natural 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 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. Under any of these gathering and processing arrangements, we may earn a fee for the services performed, or we may buy and resell the natural 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 natural gas, liquids, crude oil, and condensate moved through or by our assets.

CCS Business

We are building a carbon transportation business in support of CCS activity along the Gulf Coast, including the Mississippi River corridor in Louisiana, one of the highest CO_2 emitting regions in the United States. We believe our existing asset footprint, including our extensive network of natural gas pipelines in Louisiana, our operating expertise and our customer relationships, provide us with an advantage in building a carbon transportation business and becoming the transporter of choice in the region.

Recent Developments Affecting Industry Conditions and Our Business

Current Market Environment

The midstream energy business environment and our business are affected by the level of production of natural gas and oil in the areas in which we operate and the various factors that affect this production, including commodity prices, capital markets trends, competition, and regulatory changes. We believe these factors will continue to affect production and therefore the demand for midstream services and our business in the future. To the extent these factors vary from our underlying assumptions, our business and actual results could vary materially from market expectations and from the assumptions discussed in this section.

Production levels by our exploration and production customers for our natural gas and crude oil gathering, natural gas processing, and NGL fractionation operations are driven in large part by the level of crude oil and natural gas prices. New drilling activity is necessary to maintain or increase production levels as oil and natural gas wells experience production declines over time. New drilling activity generally moves in the same direction as crude oil and natural gas prices as those prices drive investment returns and cash flow available for reinvestment by exploration and production companies. Accordingly, our natural gas and crude oil gathering, natural gas processing, and NGL fractionation operations are affected by the level of crude, natural gas, and NGL prices, the relationship among these prices, and related activity levels from our customers. Low prices for these commodities could reduce the demand for our services and the volumes in our systems.

There has been, and we believe there will continue to be, volatility in commodity prices and in the relationships among NGL, crude oil, and natural gas prices. Oil and natural gas prices rose in the first half of 2022 due to various factors, including a rebound in demand from economic activity after COVID-19 shutdowns, supply issues, and geopolitical events, including Russia's invasion of Ukraine.

The table below presents selected average index prices for crude oil, NGL, and natural gas for the periods indicated.

	Crude oil $/Bbl (1)(2)	NGL $/Gal (1)(3)	Natural gas $/MMbtu (1)(4)
2023 by quarter:			
1st Quarter	$ 75.99	$ 0.61	$ 2.74
2nd Quarter	$ 73.56	$ 0.43	$ 2.33
3rd Quarter	$ 82.22	$ 0.50	$ 2.66
4th Quarter	$ 78.53	$ 0.45	$ 2.92
2023 Averages	**$ 77.60**	**$ 0.50**	**$ 2.66**
2022 by quarter:			
1st Quarter	$ 95.01	$ 0.92	$ 4.56
2nd Quarter	$ 108.52	$ 0.97	$ 7.50
3rd Quarter	$ 91.43	$ 0.82	$ 7.95
4th Quarter	$ 82.64	$ 0.62	$ 6.11
2022 Averages	**$ 94.33**	**$ 0.83**	**$ 6.54**

(1) 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.
(2) Crude oil closing prices based on the NYMEX futures daily close prices.
(3) Weighted average NGL closing prices based on the OPIS Napoleonville daily average spot liquids prices.
(4) Natural gas closing prices based on Henry Hub Gas Daily closing prices.

Capital markets and the demands of public investors also affect producer behavior, production levels, and our business. Over the last several years, public investors have exerted pressure on oil and natural gas producers to increase capital discipline and focus on higher investment returns even if it means lower growth. This demand by investors for increased capital discipline from energy companies led to more modest capital investment by producers, curtailed drilling and production activity, and, accordingly, slower growth for us and other midstream companies during the past few years. However, in response to the rise of oil and natural gas prices during 2021 and 2022, capital investments by United States oil and natural gas producers have risen, although global capital investments by oil and natural gas producers remain below historical levels and producers continue to remain cautious.

Producers generally focus their drilling activity on certain producing basins depending on commodity price fundamentals and favorable drilling economics. In the last few years, many producers have increasingly focused their activities in the Permian Basin, because of the availability of higher investment returns. Currently, a large percentage of all drilling rigs operating in the United States are operating in the Permian Basin. We continue to experience a robust increase in volumes in our Permian segment as our operations in that basin are in a favorable position relative to producer activity. As a result of this concentration of drilling activity in the Permian Basin, other basins, including those in which we operate in Oklahoma and North Texas, experienced reduced investment and declines in volumes produced. However, the rise in commodity prices during 2022 led to renewed producer interest in Oklahoma and North Texas, which continued into 2023. Although producer activity did rise during much of 2023, we expect that the decline in natural gas prices in the past year will dampen producer activity in these areas in 2024.

Our Louisiana segment, while subject to commodity price trends, is less dependent on gathering and processing activities and more affected by, in the case of NGLs, industrial demand for the NGLs that we supply, and in the case of natural gas, the demand for transportation of natural gas on our pipelines to industrial, utility and LNG facilities as well as to other natural gas pipelines. Industrial demand for NGLs along the Gulf Coast region has remained strong throughout 2022 and 2023, supported by regional industrial activity and export markets. Similarly, the demand for transportation of natural gas on our pipelines to industrial, utility, and LNG facilities as well as to other natural gas pipelines has remained strong throughout 2022 and 2023. Our activities and, in turn, our financial performance in the Louisiana segment are highly dependent on the availability of natural gas for transportation on our pipelines, including to our customers, and NGLs to supply our customers. To date, the availability of natural gas and NGLs to supply our customers has remained at sufficient levels, and maintaining such availability and supply is a key business focus.

Inflation

In recent years, U.S. inflation has increased significantly. In order to reduce the inflation rate, the Federal Reserve increased its target for the federal funds rate (the benchmark for most interest rates) several times in 2022 and 2023. Inflation has moderated in 2023, and the Federal Reserve has signaled an end to rate hikes and projected cuts in 2024.

To the extent that a rising cost environment impacts our results, there are typically offsetting benefits either inherent in our business or that result from other steps we take proactively to reduce the impact of inflation on our net operating results. These benefits include: (1) provisions included in our long-term fee-based revenue contracts that offset cost increases in the form of rate escalations based on positive changes in the U.S. Consumer Price Index, Producer Price Index for Finished Goods, or other factors; (2) provisions in our contracts that enable us to pass through higher costs to customers; and (3) higher commodity prices, which generally enhance our results in the form of increased volumetric throughput and demand for our services. For these reasons, the increased cost environment, caused in part by inflation, has not had a material impact on our historical results of operations for the periods presented in this report. However, a significant or prolonged period of high inflation could adversely impact our results if costs were to increase at a rate greater than the increase in the revenues we receive.

For additional discussion regarding these factors, see "Item 1A—Risk Factors—Business and Industry Risks."

Regulatory Developments

On January 20, 2021, the Biden Administration came into office and immediately issued a number of executive orders related to climate change and the production of oil and gas that could affect our operations and those of our customers, particularly those who may operate on public lands. While none of these initiatives to date have materially affected our operations or those of our customers, the Biden Administration could seek, in the future, to put into place executive orders, policy and regulatory reviews, or seek to have Congress pass legislation that could adversely affect the production of oil and natural gas, 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. 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 producer customers obtain leases, permits, and other approvals from the federal government. While the future rules and rulemaking initiatives under the Biden Administration remain uncertain, the regulations that might result from such initiatives, could lead to increased costs for us or our customers, difficulties in obtaining leases, 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. In July 2023, the DOI proposed updates to its onshore oil and gas leasing regulations which could further restrict oil and gas exploration and production on federal lands. The DOI expects to issue a final rule in the spring of 2024. These changes and uncertainties could have a negative effect on exploration and production of oil and natural gas and, consequently, negatively impact the demand for our products and services.

Over the past few years, the Biden administration has focused on regulating methane emissions in the production of oil and gas, including through venting and flaring. To this end, the EPA, BLM, and other agencies have issued regulations that may require us to make changes to our operations and may require us to pay a fee associated with our methane emissions. Additional regulatory actions targeting methane and other GHG emissions may be put in place in the future. We cannot predict, what effect, if any, such additional actions might have on our operations.

In addition, on January 26, 2024, the Biden Administration announced that it was pausing decisions on applications for new LNG export projects until the Department of Energy is able to adopt new parameters for analyzing the projects. These new parameters would include the review of the economic and environmental effects of new facilities on US climate goals and other factors. While this pause will not affect operating LNG facilities or facilities that have previously secured government approval, it will affect the approval process for future LNG facilities and for expansions of existing facilities. It is uncertain how long the pause will be in place and what changes to the analysis parameters will be adopted.

Certain enhancements were made to the IRC Section 45Q carbon sequestration tax credit as part of the Inflation Reduction Act of 2022, which was enacted on August 16, 2022. We believe these enhancements to the 45Q carbon sequestration tax credit may help expand and support the development of our CCS business, while the other provisions are not expected to have a material impact to our business, financial condition, results of operations, or cash flows.

Any regulatory changes could adversely affect our business, financial condition, results of operations or cash flows, including our ability to make cash distributions to our unitholders. For more information, see our risk factors under Item 1A—Risk Factors—"Environmental, Legal Compliance, and Regulatory Risk."

Other Recent Developments

Organic Growth and CCS Business

Tiger II Processing Plant. In April 2023, we began moving equipment and facilities associated with the non-operational Cowtown processing plant in North Texas to our Delaware Basin JV operations in the Permian. The relocation is expected to increase the processing capacity of our Permian Basin processing facilities by approximately 150 MMcf/d. We expect to complete the project in the second quarter of 2024.

GCF Operations. In January 2023, we and our partners started the process to restart the GCF assets and made capital contributions throughout the year related to the restart process. We intend to make additional capital contributions until the assets become operational, which is expected in the first half of 2024.

Matterhorn JV. We own a 15% interest in the Matterhorn JV. The Matterhorn JV is constructing a pipeline designed to transport up to 2.5 Bcf/d of natural gas through approximately 490 miles of 42-inch pipeline from the Waha Hub in West Texas to Katy, Texas (the "Matterhorn Express Pipeline"). We have made capital contributions towards the construction of the Matterhorn Express Pipeline for the years ended December 31, 2023 and 2022. We expect the Matterhorn Express Pipeline to be in service in the third quarter of 2024, pending the receipt of customary regulatory and other approvals, and we intend to make additional capital contributions until the construction is complete.

See "Item 8. Financial Statements and Supplementary Data—Note 11" for more information regarding GCF and the Matterhorn JV.

BKV Agreement. In November 2023, we began separating CO_2 from lean natural gas in our North Texas gathering systems and from rich natural gas delivered to our natural gas processing plant in Bridgeport, Texas. This CO_2 waste stream is then captured, compressed, transported, and sequestered by BKV.

ExxonMobil Agreement. In October 2022, we entered into a transportation services agreement with a subsidiary of ExxonMobil in connection with the development of a CCS project in the Mississippi River corridor in southeastern Louisiana. Under the transportation agreement, we contracted to deliver CO_2 from the Mississippi River corridor to ExxonMobil's storage location at Pecan Island in Vermilion Parish, Louisiana, beginning in 2025. The agreement also provides for a reserved capacity available of up to 10 million metric tonnes per year, with an initial reserved capacity of 3.2 million metric tonnes per year. In February 2024, we announced that we and ExxonMobil have agreed to reassess the Pecan Island project's near-term role, with the expectation that other joint CCS opportunities along the Gulf Coast, and beyond the Mississippi River corridor, may be prioritized ahead of the Pecan Island project.

Divestitures

On November 1, 2023, we sold certain ORV crude assets in our Louisiana segment to a subsidiary of Ergon, Inc. in exchange for cash consideration of approximately $59.2 million, subject to post-closing purchase price adjustments, and a contingent payment of an additional $0.5 million subject to the buyer's pursuit of certain commercial opportunities within three years after the acquisition date.

On November 3, 2023, we sold our remaining ORV assets in our Louisiana segment to Blue Racer Midstream, LLC in exchange for cash consideration of approximately $9.8 million, subject to post-closing purchase price adjustments.

Debt

Senior Unsecured Notes Issuance. In April 2023, we completed the sale of an additional $300.0 million aggregate principal amount of ENLC's 6.50% senior unsecured notes due 2030 (the "Additional Notes") at a price to the public of 99% of their face value. The Additional Notes were offered as an additional issuance of our existing 6.50% senior unsecured notes due 2030 that we issued on August 31, 2022 in an aggregate principal amount of $700.0 million. Net proceeds of approximately $294.5 million were used to repay a portion of the borrowings under the Revolving Credit Facility. The Additional Notes are fully and unconditionally guaranteed by ENLK. See "Item 8. Financial Statements and Supplementary Data—Note 7" for more information regarding the issuance of new senior unsecured notes by us.

Equity

Common Unit Repurchase Program. For the year ended December 31, 2023, we repurchased 11,530,962 outstanding common units in open market purchases, for an aggregate cost, including commissions, of $134.5 million, or an average of $11.67 per common unit.

GIP Repurchase Agreement. For the year ended December 31, 2023, we repurchased 8,846,445 ENLC common units held by GIP for an aggregate cost of $98.3 million, or an average of $11.11 per common unit.

Additionally, on February 19, 2024, we repurchased 3,280,637 ENLC common units held by GIP at an aggregate cost of $41.5 million, or an average of $12.66 per common unit. These units represented GIP's pro rata share of the aggregate number of common units repurchased by us during the three months ended December 31, 2023. The per unit price we paid to GIP was the same as the average per unit price paid by us for publicly held ENLC common units repurchased during the same period, less broker commissions, which were not paid with respect to the GIP units. As of December 31, 2023, $41.5 million is classified as "Other current liabilities" on the consolidated balance sheets related to our obligation to repurchase our common units from GIP.

See "Item 8. Financial Statements and Supplementary Data—Note 10" for more information regarding our common unit repurchases.

ENLK's *Eleventh Amended and Restated Agreement of Limited Partnership.* In September 2023, in connection with ENLK's qualification of the Series B Preferred Units to be eligible to be deposited through the Depository Trust Company, we amended and restated the limited partnership agreement of ENLK to, among other things, (i) reflect the cancellation of all outstanding ENLC Class C Common Units, which were non-economic equity interests previously held by the holders of the Series B Preferred Units and permitted such holders to participate in any vote of the holders of ENLC common units, (ii) provide for the termination of any rights of the holders of the Series B Preferred Units to PIK Distributions with respect to, and following, the earlier to occur of (x) any quarter in which the holders of the Series B Preferred Units give notice to the General Partner of its election to terminate such PIK Distribution right and (y) the quarter ending June 30, 2024, and (iii) in connection with such termination of PIK Distributions, increase the cash distribution per Series B Preferred Unit from $0.28125 to $0.31875, in addition to the continued payment of the Series B Excess Cash Payment Amount (as defined in ENLK's limited partnership agreement).

Repurchase of Series C Preferred Units. For the year ended December 31, 2023, we repurchased 14,500 Series C Preferred Units for total consideration of $13.1 million. For the year ended December 31, 2022, we repurchased 19,000 Series C Preferred Units for total consideration of $15.2 million.

See "Item 8. Financial Statements and Supplementary Data—Note 9" for more information regarding the Series B Preferred Units and Series C Preferred Units.

Rate Reset

Beginning in 2024, certain legacy contracts in the Oklahoma and North Texas segments experienced a one-time rate reset. The rate reset was negotiated in 2018 in exchange for adding an additional five years of term to these contracts. The rate reset is a one-time adjustment down to a pre-negotiated rate (which partially reverses recent annual inflation cost escalation adjustments). These contracts are set to expire between 2029 and 2033 and continue to have cost escalation provisions that allow for rate increases from the reset rate based on future changes in inflation. For 2024, we expect our adjusted gross margin to decline by approximately $40 million related to the rate reset under these contracts.

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"); 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. 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 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 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,	
	2023	2022
Total revenues	$ 6,900.1	$ 9,542.1
Cost of sales, exclusive of operating expenses and depreciation and amortization	(4,856.1)	(7,572.8)
Operating expenses	(558.2)	(524.9)
Depreciation and amortization	(657.1)	(639.4)
Gross margin	828.7	805.0
Operating expenses	558.2	524.9
Depreciation and amortization	657.1	639.4
Adjusted gross margin	$ 2,044.0	$ 1,969.3

Adjusted EBITDA

We define adjusted EBITDA as net income (loss) plus (less) interest expense, net of interest income; depreciation and amortization; impairments; (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 derivatives; costs associated with the relocation of processing facilities; accretion expense associated with asset retirement obligations; transaction costs; non-cash expense related to changes in the fair value of contingent consideration; (non-cash rent); and (non-controlling interest share of adjusted EBITDA from joint ventures). Adjusted EBITDA is one of the primary metrics 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 income to adjusted EBITDA (in millions):

	Year Ended December 31,	
	2023	2022
Net income	$ 350.0	$ 500.7
Interest expense, net of interest income	271.7	245.0
Depreciation and amortization	657.1	639.4
Impairments	20.7	—
Loss from unconsolidated affiliate investments	8.2	5.6
Distributions from unconsolidated affiliate investments	2.5	0.7
(Gain) loss on disposition of assets	(0.3)	18.0
Loss on extinguishment of debt	—	6.2
Unit-based compensation	19.2	30.4
Income tax expense (benefit)	62.8	(94.9)
Unrealized (gain) loss on commodity derivatives	12.1	(40.2)
Costs associated with the relocation of processing facilities (1)	14.6	43.8
Other (2)	0.1	(2.4)
Adjusted EBITDA before non-controlling interest	1,418.7	1,352.3
Non-controlling interest share of adjusted EBITDA from joint ventures (3)	(68.7)	(67.7)
Adjusted EBITDA, net to ENLC	$ 1,350.0	$ 1,284.6

(1) Represents cost incurred to execute discrete, project-based strategic initiatives aimed at realigning available processing capacity from our Oklahoma and North Texas segments to the Permian segment. These costs are not part of our ongoing operations.

(2) Includes transaction costs, non-cash expense related to changes in the fair value of contingent consideration, accretion expense associated with asset retirement obligations, and non-cash rent, which relates to lease incentives pro-rated over the lease term.

(3) Non-controlling interest share of adjusted EBITDA from joint ventures includes NGP’s 49.9% share of adjusted EBITDA from the Delaware Basin JV and Marathon Petroleum Corporation’s 50% share of adjusted EBITDA from the Ascension JV.

Free Cash Flow After Distributions

We define free cash flow after distributions as adjusted EBITDA, net to ENLC, plus (less) (growth and maintenance capital expenditures, excluding capital expenditures that were contributed by other entities and relate to the non-controlling interest share of our consolidated entities); (interest expense, net of interest income); (distributions declared on common units); (cash distributions earned by the Series B Preferred Units and the Series C Preferred Units); (payment to redeem mandatorily redeemable non-controlling interest); (costs associated with the relocation of processing facilities, excluding costs that were contributed by other entities and relate to the non-controlling interest share of our consolidated entities); non-cash interest (income)/expense; (contributions to investment in unconsolidated affiliates); (payments to terminate interest rate swaps); (current income taxes); and proceeds from the sale of equipment and land.

Free cash flow after distributions is the principal cash flow metric used by the Company. It is also used as a supplemental liquidity measure by our management and by external users of our financial statements, such as investors, commercial banks, research analysts, and others, to assess the ability of our assets to generate cash sufficient to pay interest costs, pay back our indebtedness, make cash distributions, and make 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.

The GAAP measure most directly comparable to free cash flow after distributions is net cash provided by operating activities. Free cash flow after distributions should not be considered an alternative to, or more meaningful than, net income (loss), operating income (loss), net cash provided by operating activities, or any other measure of liquidity presented in accordance with GAAP. Free cash flow after distributions has important limitations because it excludes some items that affect net income (loss), operating income (loss), and net cash provided by operating activities. Free cash flow after distributions may not be comparable to similarly titled measures of other companies because other companies may not calculate this non-GAAP metric 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 free cash flow after distributions, to evaluate our overall liquidity.

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

	Year Ended December 31, 2023	Year Ended December 31, 2022
Net cash provided by operating activities	$ 1,222.7	$ 1,049.3
Interest expense (1)	265.3	237.6
Utility credits redeemed (2)	(1.5)	(31.1)
Accruals for settled commodity derivative transactions	—	(1.9)
Distributions from unconsolidated affiliate investment in excess of earnings	2.5	0.7
Costs associated with the relocation of processing facilities (3)	14.6	43.8
Other (4)	(0.7)	2.3
Changes in operating assets and liabilities which (provided) used cash:		
Accounts receivable, accrued revenues, inventories, and other	(155.2)	12.6
Accounts payable, accrued product purchases, and other accrued liabilities	71.0	39.0
Adjusted EBITDA before non-controlling interest	1,418.7	1,352.3
Non-controlling interest share of adjusted EBITDA from joint ventures (5)	(68.7)	(67.7)
Adjusted EBITDA, net to ENLC	1,350.0	1,284.6
Growth capital expenditures, net to ENLC (6)	(354.8)	(267.1)
Maintenance capital expenditures, net to ENLC (6)	(69.4)	(44.9)
Interest expense, net of interest income	(271.7)	(238.5)
Distributions declared on common units	(234.3)	(222.5)
ENLK preferred unit cash distributions earned (7)	(97.0)	(93.2)
Payment to redeem mandatorily redeemable non-controlling interest (8)	(10.5)	—
Costs associated with the relocation of processing facilities, net to ENLC (3)(6)(9)	(0.7)	(43.8)
Contributions to investment in unconsolidated affiliates	(68.1)	(65.9)
Other (10)	3.5	3.7
Free cash flow after distributions	$ 247.0	$ 312.4

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(1) Net of amortization of debt issuance costs, net discount of senior unsecured notes, and designated cash flow hedge, which are included in interest expense but not included in net cash provided by operating activities, and non-cash interest income, which is netted against interest expense but not included in adjusted EBITDA.

(2) Under our utility agreements, we are entitled to a base load of electricity and pay or receive credits, based on market pricing, when we exceed or do not use the base load amounts. In 2021, we received credits from our utility providers based on market rates for our unused electricity during Winter Storm Uri that we have fully redeemed as of December 31, 2023.

(3) Represents cost incurred to execute discrete, project-based strategic initiatives aimed at realigning available processing capacity from our Oklahoma and North Texas segments to the Permian segment. These costs are not part of our ongoing operations.

(4) Includes transaction costs, current income tax expense, and non-cash rent, which relates to lease incentives pro-rated over the lease term.

(5) Non-controlling interest share of adjusted EBITDA from joint ventures includes NGP's 49.9% share of adjusted EBITDA from the Delaware Basin JV and Marathon Petroleum Corporation's 50% share of adjusted EBITDA from the Ascension JV.

(6) Excludes capital expenditures and costs associated with the relocation of processing facilities that were contributed by other entities and relate to the non-controlling interest share of our consolidated entities.

(7) 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 9" 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.

(8) In January 2023, we settled the redemption of the mandatorily redeemable non-controlling interest in one of our non-wholly owned subsidiaries. See "Item 8. Financial Statements and Supplementary Data—Note 2" for more information regarding the redemption.

(9) Includes a one-time $8.0 million contribution from an affiliate of NGP in May 2023 in connection with the Delaware Basin JV's purchase of the Cowtown processing plant.

(10) Includes non-cash interest expense, current income tax expense, and proceeds from the sale of surplus or unused equipment and land, which occurred in the normal operation of our business.

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 tables below (in millions, except volumes):

	Permian	Louisiana	Oklahoma	North Texas	Corporate	Totals
Year Ended December 31, 2023						
Total revenues	$ 2,823.2	$ 3,910.3	$ 1,171.4	$ 721.2	$ (1,726.0)	$ 6,900.1
Cost of sales, exclusive of operating expenses and depreciation and amortization	(2,205.5)	(3,388.4)	(645.6)	(342.6)	1,726.0	(4,856.1)
Adjusted gross margin	617.7	521.9	525.8	378.6	—	2,044.0
Operating expenses	(221.3)	(130.3)	(103.8)	(102.8)	—	(558.2)
Segment profit	396.4	391.6	422.0	275.8	—	1,485.8
Depreciation and amortization	(166.6)	(151.3)	(217.7)	(115.8)	(5.7)	(657.1)
Gross margin	$ 229.8	$ 240.3	$ 204.3	$ 160.0	$ (5.7)	$ 828.7

	Permian	Louisiana	Oklahoma	North Texas	Corporate	Totals
Year Ended December 31, 2022						
Total revenues	$ 3,866.0	$ 5,977.4	$ 1,603.0	$ 1,021.7	$ (2,926.0)	$ 9,542.1
Cost of sales, exclusive of operating expenses and depreciation and amortization	(3,280.3)	(5,462.4)	(1,124.4)	(631.7)	2,926.0	(7,572.8)
Adjusted gross margin	585.7	515.0	478.6	390.0	—	1,969.3
Operating expenses	(200.2)	(140.7)	(90.9)	(93.1)	—	(524.9)
Segment profit	385.5	374.3	387.7	296.9	—	1,444.4
Depreciation and amortization	(154.5)	(156.5)	(201.8)	(121.1)	(5.5)	(639.4)
Gross margin	$ 231.0	$ 217.8	$ 185.9	$ 175.8	$ (5.5)	$ 805.0

	Permian	Louisiana	Oklahoma	North Texas	Corporate	Totals
Year Ended December 31, 2021						
Total revenues	$ 2,307.3	$ 4,539.8	$ 1,204.2	$ 860.4	$ (2,225.8)	$ 6,685.9
Cost of sales, exclusive of operating expenses and depreciation and amortization	(1,996.1)	(4,091.2)	(796.6)	(531.8)	2,225.8	(5,189.9)
Adjusted gross margin	311.2	448.6	407.6	328.6	—	1,496.0
Operating expenses	(81.5)	(123.7)	(80.0)	(77.7)	—	(362.9)
Segment profit	229.7	324.9	327.6	250.9	—	1,133.1
Depreciation and amortization	(139.9)	(141.0)	(204.3)	(114.3)	(8.0)	(607.5)
Gross margin	$ 89.8	$ 183.9	$ 123.3	$ 136.6	$ (8.0)	$ 525.6

	Year Ended December 31,		
	2023	2022	2021
Midstream Volumes:			
Consolidated			
Gathering and Transportation (MMbtu/d)	7,096,300	6,913,600	5,597,600
Processing (MMbtu/d)	3,746,600	3,384,300	2,866,500
Crude Oil Handling (Bbls/d)	205,500	197,500	170,700
NGL Fractionation (Gals/d)	8,752,800	8,605,800	8,412,600
Brine Disposal (Bbls/d)	2,500	3,000	2,700
Permian Segment			
Gathering and Transportation (MMbtu/d)	1,800,900	1,506,600	1,067,000
Processing (MMbtu/d)	1,662,400	1,422,200	1,010,000
Crude Oil Handling (Bbls/d)	165,300	156,300	134,600
Louisiana Segment			
Gathering and Transportation (MMbtu/d)	2,495,000	2,828,200	2,160,800
Crude Oil Handling (Bbls/d)	14,900	17,400	15,900
NGL Fractionation (Gals/d)	7,705,700	7,957,800	7,455,600
Brine Disposal (Bbls/d)	2,500	3,000	2,700
Oklahoma Segment			
Gathering and Transportation (MMbtu/d)	1,221,000	1,031,200	992,400
Processing (MMbtu/d)	1,182,000	1,057,600	1,010,300
Crude Oil Handling (Bbls/d)	25,300	23,800	20,200
North Texas Segment			
Gathering and Transportation (MMbtu/d)	1,579,400	1,547,600	1,377,400
Processing (MMbtu/d)	734,600	705,100	631,500

Year Ended December 31, 2023 Compared to Year Ended December 31, 2022

Revenues and Cost of Sales, Exclusive of Operating Expenses and Depreciation and Amortization.

Our consolidated and segment revenues and cost of sales, exclusive of operating expenses and depreciation and amortization, are from natural gas, NGL, crude oil, and condensate product sales and purchases, midstream services that we perform with respect to those commodities, and derivative activity. Fluctuations in our consolidated and segment revenues and cost of sales, exclusive of operating expenses and depreciation and amortization, reflect in large part changes in commodity prices and volumes. Our adjusted gross margin is not directly affected by the commodity price environment because the commodities that we buy and sell are generally based on the same pricing indices. Both consolidated and segment product sales revenues and cost of sales, exclusive of operating expenses and depreciation and amortization, will fluctuate with market prices; however, the adjusted gross margin related to those sales and purchases will not necessarily have a corresponding increase or decrease. Additionally, fluctuations in these measures from changes in commodity prices may be offset by gains or losses from derivative instruments that we use to manage our exposure to commodity price risk associated with such sales and purchases.

Total revenues and cost of sales, exclusive of operating expenses and depreciation and amortization, decreased $2,642.0 million and $2,716.7 million, respectively, for the year ended December 31, 2023 compared to the year ended December 31, 2022 due to the following:

- Product sales revenues decreased $2,809.3 million for the year ended December 31, 2023 compared to the year ended December 31, 2022 primarily due to:
  - A $1,554.4 million decrease in natural gas sales primarily driven by lower natural gas prices,
  - A $1,185.8 million decrease in NGL sales primarily driven by lower NGL prices, and
  - A $69.1 million decrease in crude oil and condensate sales primarily driven by lower crude oil prices.
- Lower natural gas, NGL, and crude oil prices also had a corresponding impact to cost of sales, exclusive of operating expenses and depreciation and amortization, contributing to the $2,716.7 million decrease for the year ended December 31, 2023 compared to the year ended December 31, 2022.
- Revenues from midstream services increased $160.9 million for the year ended December 31, 2023 compared to the year ended December 31, 2022 primarily due to:
  - A $113.9 million increase in gathering and transportation revenues primarily driven by higher gathering and transportation volumes,
  - A $43.2 million increase in processing revenues primarily driven by higher processing volumes, and
  - A $5.3 million increase in NGL service revenues primarily driven by higher NGL service volumes.

  These increases were primarily offset by the disposition of our ORV crude assets, which contributed to the $8.6 million decrease in crude services revenues.
- Derivative gains increased $6.4 million for the year ended December 31, 2023 compared to the year ended December 31, 2022 due to $52.3 million of increased unrealized losses and $58.7 million of increased realized gains.

Operating Expenses. Operating expenses increased $33.3 million for the year ended December 31, 2023 compared to the year ended December 31, 2022 primarily due to a $20.5 million increase in compressor rentals, a $7.3 million increase in materials and supplies expense, a $5.6 million increase in ad valorem taxes, a $4.4 million increase in labor and benefits costs, a $4.1 million increase in utilities expense, a $3.3 million increase in compressor overhauls, a $2.8 million increase in insurance costs, and a $2.8 million increase in regulatory and compliance costs. These increases were partially offset by a $14.4 million decrease in construction fees and services and a $3.6 million decrease in sales and use tax.

Depreciation and Amortization. Depreciation and amortization increased $17.7 million for the year ended December 31, 2023 compared to the year ended December 31, 2022 primarily due to a $26.2 million increase resulting from changes in estimated useful lives, an $11.9 million increase due to additional assets placed in service, a $6.4 million increase related to the Barnett Shale Acquisition in July 2022, and a $3.8 million increase related to the Central Oklahoma Acquisition in December 2022. These increases were partially offset by a $31.1 million decrease in depreciation related to assets reaching the end of their depreciable lives.

Impairments. For the year ended December 31, 2023, we recognized an impairment expense of $20.7 million due to changes in our outlook for future cash flows and the anticipated use of certain ORV crude assets in our Louisiana segment. We determined that the carrying amounts of these assets exceeded their fair value, based on market inputs and certain assumptions.

(Gain) Loss on Disposition of Assets. For the year ended December 31, 2023, we recognized a gain on disposition of assets of $0.3 million, which was primarily due to the divestitures of our ORV assets in our Louisiana segment. See "Item 8. Financial Statements and Supplementary Data—Note 3" for additional information. For the year ended December 31, 2022, we recognized a loss on disposition of assets of $18.0 million, which was primarily due to the sale of compressor units associated with our ORV assets. (Gain) loss on disposition of assets consisted of the following amounts (in millions):

	Year Ended December 31,	
	2023	2022
Net book value of assets disposed	$ 72.9	$ 30.8
Proceeds from sales	(73.1)	(12.8)
Insurance recoveries	(0.1)	—
(Gain) loss on disposition of assets	$ (0.3)	$ 18.0

General and Administrative Expenses. General and administrative expenses were $115.5 million for the year ended December 31, 2023 compared to $125.2 million for the year ended December 31, 2022, a decrease of $9.7 million. The decrease was primarily due to a $9.2 million decrease in unit-based compensation and a $4.0 million decrease in consulting fees and services. The decrease was partially offset by a $3.9 million increase in losses related to an increase in the estimated fair value of the contingent consideration associated with the Amarillo Rattler Acquisition and the Central Oklahoma Acquisition. See "Item 8. Financial Statements and Supplementary Data—Note 3" for more additional information regarding the contingent consideration for Amarillo Rattler and the Central Oklahoma Acquisition.

Interest Expense, Net of Interest Income. Interest expense, net of interest income, was $271.7 million for the year ended December 31, 2023 compared to $245.0 million for the year ended December 31, 2022, an increase of $26.7 million. Interest expense, net of interest income, consisted of the following (in millions):

	Year Ended December 31,	
	2023	2022
ENLK and ENLC senior unsecured notes	$ 230.1	$ 206.0
Revolving Credit Facility	17.9	13.5
AR Facility	22.8	12.1
Amortization of debt issuance costs and net discount of senior unsecured notes	6.4	5.5
Interest rate swaps - realized	(4.5)	1.9
Redemption of mandatorily redeemable non-controlling interest	—	6.5
Other	(1.0)	(0.5)
Interest expense, net of interest income	$ 271.7	$ 245.0

Loss on Extinguishment of Debt. We recognized a loss on extinguishment of debt of $6.2 million for the year ended December 31, 2022, which was primarily due to the repurchases of ENLK's senior unsecured notes in the debt tender offer completed in the third quarter of 2022. For the year ended December 31, 2023, we and ENLK did not repurchase any senior unsecured notes. See "Item 8. Financial Statements and Supplementary Data—Note 7" for additional information.

Loss from Unconsolidated Affiliate Investments. Loss from unconsolidated affiliate investments was $8.2 million for the year ended December 31, 2023 compared to $5.6 million for the year ended December 31, 2022, an increase in loss of $2.6 million. The increase in loss was primarily attributable to a $1.2 million increase in loss related to our GCF investment, a $0.9 million increase in loss related to the Matterhorn JV, and a $0.5 million increase in loss related to the Cedar Cove JV. See "Item 8. Financial Statements and Supplementary Data—Note 11" for additional information.

Income Tax Benefit (Expense). Income tax expense was $62.8 million for the year ended December 31, 2023 compared to an income tax benefit of $94.9 million for the year ended December 31, 2022. The increase in income tax expense for the year ended December 31, 2023 was primarily attributable to the reduction of the valuation allowance recorded on our deferred tax assets for the year ended December 31, 2022, which resulted in an income tax benefit for the year ended December 31, 2022. See "Item 8. Financial Statements and Supplementary Data—Note 8" for additional information.

Net Income Attributable to Non-Controlling Interest. Net income attributable to non-controlling interest was $143.8 million for the year ended December 31, 2023 compared to net income of $139.4 million for the year ended December 31, 2022, an increase of $4.4 million. Our non-controlling interests are comprised of Series B Preferred Units, Series C Preferred Units, NGP's 49.9% share of the Delaware Basin JV, and Marathon Petroleum Corporation's 50% share of the Ascension JV. The increase was primarily due to an $11.8 million increase in income attributable to the Series C Preferred Units and a $0.9 million increase attributable to Marathon Petroleum Corporation's 50% share of the Ascension JV. The increase was partially offset by a $6.4 million decrease in income attributable to NGP's 49.9% share of the Delaware Basin JV and a $1.9 million decrease attributable to the Series B Preferred Units.

Analysis of Operating Segments

We manage and report our operations primarily according to the geography and the nature of the activity. We have five reportable segments: Permian segment, Louisiana segment, Oklahoma segment, North Texas segment, and Corporate segment. We evaluate the performance of our operating segments based on segment profit and adjusted gross margin. The GAAP measure most directly comparable to segment profit and adjusted gross margin is gross margin. We believe that investors benefit from having access to the same financial measures that our management uses to evaluate segment results.

See below for our discussion of segment results for the year ended December 31, 2023 compared to the year ended December 31, 2022.

- *Permian Segment.*

  - Revenues and cost of sales, exclusive of operating expenses and depreciation and amortization, decreased $1,042.8 million and $1,074.8 million, respectively, resulting in an increase in adjusted gross margin in the Permian segment of $32.0 million, due to:

    - A $26.3 million increase in adjusted gross margin associated with our Permian natural gas assets. Adjusted gross margin, excluding derivative activity, increased $27.7 million, which was primarily due to higher volumes from existing customers. Derivative activity associated with our Permian natural gas assets decreased adjusted gross margin by $1.4 million, which included $18.0 million from increased realized gains and $19.4 million from increased unrealized losses.
    - A $5.7 million increase in adjusted gross margin associated with our Permian crude assets. Adjusted gross margin, excluding derivative activity, increased $6.9 million, which was primarily due to higher commodity prices. Derivative activity associated with our Permian crude assets decreased adjusted gross margin by $1.2 million, which included $6.0 million from increased realized losses and $4.8 million from increased unrealized gains.

  - Operating expenses in the Permian segment increased $21.1 million primarily due to a $12.9 million increase in compressor rentals, an $11.5 million increase in utilities expense, a $5.3 million increase in labor and benefits costs, a $3.0 million increase in compressor overhauls, and a $2.1 million increase in materials and supplies expense. These increases in operating expenses were principally due to an increase in operating activity. These increases were partially offset by a $14.1 million decrease in construction fees and services.

  - Depreciation and amortization in the Permian segment increased $12.1 million primarily due to $7.0 million increase resulting from additional assets placed in service and a $5.0 million increase related to the equipment transferred to the Phantom processing facility.

- *Louisiana Segment.*

  - Revenues and cost of sales, exclusive of operating expenses and depreciation and amortization, decreased $2,067.1 million and $2,074.0 million, respectively, resulting in an increase in adjusted gross margin in the Louisiana segment of $6.9 million, due to:

    - A $9.7 million increase in adjusted gross margin associated with our Louisiana NGL transmission and fractionation assets. Adjusted gross margin, excluding derivative activity, increased $22.7 million, which was primarily due to fluctuations in market prices. Derivative activity associated with our Louisiana NGL transmission and fractionation assets decreased adjusted gross margin by $13.0 million, which included $4.1 million from decreased realized gains and $8.9 million from increased unrealized losses.
    - A $15.7 million increase in adjusted gross margin associated with our Louisiana natural gas assets. Adjusted gross margin, excluding derivative activity, increased $7.2 million, which was primarily due to a settlement payment resulting from a customer account dispute in the amount of $6.8 million. Derivative activity associated with our Louisiana natural gas assets increased adjusted gross margin by $8.5 million, which included $3.2 million from decreased realized losses and $5.3 million from increased unrealized gains.
    - An $18.5 million decrease in adjusted gross margin associated with our ORV crude assets. Adjusted gross margin, excluding derivative activity, decreased $19.1 million, which was primarily due to lower compression fee revenue resulting from the sale of several compressor units in December 2022 and the divestitures of our ORV assets in November 2023. Derivative activity associated with our ORV crude assets increased adjusted gross margin by $0.6 million from increased realized gains.

  - Operating expenses in the Louisiana segment decreased $10.4 million primarily due to an $8.2 million decrease in utilities expense, a $1.8 million decrease in labor and benefits costs, and a $1.6 million decrease in vehicle expenses related to the disposal of the heavy truck fleet in ORV. These decreases were partially offset by a $0.8 million increase in regulatory and compliance costs and a $0.7 million increase in ad valorem taxes.

  - Depreciation and amortization in the Louisiana segment decreased $5.2 million primarily due to a $14.5 million decrease resulting from assets reaching the end of their depreciable lives and a $4.1 million decrease related to the sale of several compressor units associated with our ORV assets in December 2022. These decreases were partially offset by an $8.9 million increase in depreciation due to changes in estimated useful lives and a $4.2 million increase related to the divestitures of our ORV assets in November 2023.

- *Oklahoma Segment.*

  - Revenues and cost of sales, exclusive of operating expenses and depreciation and amortization, decreased $431.6 million and $478.8 million, respectively, resulting in an increase in adjusted gross margin in the Oklahoma segment of $47.2 million, due to:

    - A $44.7 million increase in adjusted gross margin associated with our Oklahoma natural gas assets. Adjusted gross margin, excluding derivative activity, increased $33.8 million, which was primarily due to additional volumes from the Central Oklahoma Acquisition in December 2022. Derivative activity associated with our Oklahoma natural gas assets increased adjusted gross margin by $10.9 million, which included $18.7 million from increased realized gains and $7.8 million from increased unrealized losses.
    - A $2.5 million increase in adjusted gross margin associated with our Oklahoma crude assets. Adjusted gross margin, excluding derivative activity, increased $1.6 million, which was primarily due to higher volumes from existing customers. Derivative activity associated with our Oklahoma crude assets increased adjusted gross margin by $0.9 million from increased realized gains.

  - Operating expenses in the Oklahoma segment increased $12.9 million primarily due to a $6.6 million increase in compressor rentals, a $4.8 million increase in ad valorem taxes, a $2.8 million increase in materials and supplies expense, a $1.9 million increase in labor and benefit costs, and a $0.9 million increase in insurance costs. These increases in operating expenses were principally due to an increase in operating activity from the Central Oklahoma Acquisition in December 2022. These increases were partially offset by a $3.4 million decrease in construction fees and services and a $1.3 million decrease in compressor overhauls.

- ◦ Depreciation and amortization in the Oklahoma segment increased $15.9 million primarily due to a $12.5 million increase resulting from changes in estimated useful lives, a $4.6 million increase related to additional assets placed in service, and a $3.8 million increase related to the Central Oklahoma Acquisition in December 2022. These increases were partially offset by a $5.0 million decrease in depreciation related to the transfer of equipment to the Phantom processing facility.

- *North Texas Segment.*

  - ◦ Revenues and cost of sales, exclusive of operating expenses and depreciation and amortization, decreased $300.5 million and $289.1 million, respectively, resulting in a decrease in adjusted gross margin in the North Texas segment of $11.4 million. Adjusted gross margin, excluding derivative activity, decreased $12.5 million, which was primarily due to lower market prices. Derivative activity associated with our North Texas segment increased adjusted gross margin by $1.1 million, which included $27.4 million from increased realized gains and $26.3 million from increased unrealized losses.

  - ◦ Operating expenses in the North Texas segment increased $9.7 million primarily due to a $2.2 million increase in construction fees and services, a $2.0 million increase in materials and supplies expense, a $1.2 million increase in labor and benefits costs, a $1.1 million increase in compressor overhauls, a $1.0 million increase in pipeline integrity compliance costs, a $1.0 million increase in compressor rentals, a $0.5 million increase in utilities expense, and a $0.5 million increase in insurance costs.

  - ◦ Depreciation and amortization in the North Texas segment decreased $5.3 million primarily due to a $16.6 million decrease resulting from assets reaching the end of their depreciable lives, which was partially offset by a $6.4 million increase in depreciation related to the Barnett Shale Acquisition in July 2022 and a $4.7 million decrease resulting from changes in estimated useful lives.

- *Corporate Segment.*

  - ◦ Revenues and cost of sales, exclusive of operating expenses and depreciation and amortization, each increased $1,200.0 million. The corporate segment includes offsetting eliminations related to intercompany revenues and cost of sales, exclusive of operating expenses and depreciation and amortization.

  - ◦ Depreciation and amortization in the Corporate segment increased $0.2 million due to additional assets placed in service.

Year Ended December 31, 2022 Compared to Year Ended December 31, 2021

Revenues and Cost of Sales, Exclusive of Operating Expenses and Depreciation and Amortization.

Our consolidated and segment revenues and cost of sales, exclusive of operating expenses and depreciation and amortization, are from natural gas, NGL, crude oil, and condensate product sales and purchases, midstream services that we perform with respect to those commodities, and derivative activity. Fluctuations in our consolidated and segment revenues and cost of sales, exclusive of operating expenses and depreciation and amortization, reflect in large part changes in commodity prices and volumes. Our adjusted gross margin is not directly affected by the commodity price environment because the commodities that we buy and sell are generally based on the same pricing indices. Both consolidated and segment product sales revenues and cost of sales, exclusive of operating expenses and depreciation and amortization, will fluctuate with market prices; however, the adjusted gross margin related to those sales and purchases will not necessarily have a corresponding increase or decrease. Additionally, fluctuations in these measures from changes in commodity prices may be offset by gains or losses from derivative instruments that we use to manage our exposure to commodity price risk associated with such sales and purchases.

Total revenues and cost of sales, exclusive of operating expenses and depreciation and amortization, increased $2,856.2 million and $2,382.9 million, respectively, for the year ended December 31, 2022 compared to the year ended December 31, 2021 due to the following:

- Product sales revenues increased $2,570.9 million for the year ended December 31, 2022 compared to the year ended December 31, 2021 primarily due to:

  - ◦ A $1,047.3 million increase in natural gas sales primarily driven by higher natural gas prices,
  - ◦ An $850.2 million increase in NGL sales primarily driven by higher NGL prices, and
  - ◦ A $673.4 million increase in crude oil and condensate sales primarily driven by higher crude oil prices.

- Higher natural gas, NGL, and crude oil prices also had a corresponding impact to cost of sales, exclusive of operating expenses and depreciation and amortization, contributing to the $2,382.9 million increase for the year ended December 31, 2022 compared to the year ended December 31, 2021.

- Revenues from midstream services increased $111.9 million for the year ended December 31, 2022 compared to the year ended December 31, 2021 primarily due to:

  - A $65.9 million increase in gathering and transportation revenues primarily driven by higher gathering and transportation volumes, and
  - A $47.8 million increase in processing revenues primarily driven by higher processing volumes.

- Derivative gains increased $173.4 million for the year ended December 31, 2022 compared to the year ended December 31, 2021 due to $120.8 million of decreased realized losses and $52.6 million of increased unrealized gains.

Operating Expenses. Operating expenses increased $162.0 million primarily due to a $73.3 million increase in utilities expense primarily related to electricity credits earned in 2021 that did not recur in 2022, a $31.7 increase in construction fees and services, a $27.5 million increase in materials and supplies expense, a $12.7 million increase in labor and benefits costs, and an $11.3 million increase in compressor rentals. These increases in operating expenses were principally due to an increase in operating activity.

Depreciation and Amortization. Depreciation and amortization increased $31.9 million primarily due to additional assets placed into service.

General and Administrative Expenses. General and administrative expenses were $125.2 million for the year ended December 31, 2022 compared to $107.8 million for the year ended December 31, 2021, an increase of $17.4 million. The increase was primarily due to a $6.4 million increase in labor and benefits costs, a $6.0 million increase in unit-based compensation, and a $5.8 million increase in consulting fees and services. The increase was partially offset by a $2.7 million increase in gains related to a decrease in the estimated fair value of the contingent consideration associated with the Amarillo Rattler Acquisition.

Analysis of Operating Segments

We manage and report our operations primarily according to the geography and the nature of the activity. We have five reportable segments: Permian segment, Louisiana segment, Oklahoma segment, North Texas segment, and Corporate segment. We evaluate the performance of our operating segments based on segment profit and adjusted gross margin. The GAAP measure most directly comparable to segment profit and adjusted gross margin is gross margin. We believe that investors benefit from having access to the same financial measures that our management uses to evaluate segment results.

See below for our discussion of segment results for the year ended December 31, 2022 compared to the year ended December 31, 2021.

- *Permian Segment.*
  - Revenues and cost of sales, exclusive of operating expenses and depreciation and amortization, increased $1,558.7 million and $1,284.2 million, respectively, resulting in an increase in adjusted gross margin in the Permian segment of $274.5 million, due to:
    - A $259.7 million increase in adjusted gross margin associated with our Permian natural gas assets. Adjusted gross margin, excluding derivative activity, increased $174.2 million, which was primarily due to higher volumes from increased producer activity. Derivative activity associated with our Permian natural gas assets increased adjusted gross margin by $85.5 million, which included $69.0 million from decreased realized losses and $16.5 million from increased unrealized gains.
    - A $14.8 million increase in adjusted gross margin associated with our Permian crude assets. Adjusted gross margin, excluding derivative activity, increased $16.4 million, which was primarily due to higher volumes from increased producer activity. Derivative activity associated with our Permian crude assets decreased adjusted gross margin by $1.6 million, which included $2.4 million from decreased realized gains and $0.8 million from decreased unrealized losses.
  - Operating expenses in the Permian segment increased $118.7 million. During the year ended December 31, 2021, our Permian operating expenses were reduced by $46.5 million due to electricity credits earned during Winter Storm Uri in February 2021 that were not available during the same period of 2022. Operating expenses also increased primarily due to a $22.5 million increase in construction fees and services, a $15.0 million increase in materials and supplies expense, a $12.4 million increase in utilities expense, a $10.6 million increase in compressor rentals, and a $3.8 million increase in labor and benefits costs. These increases in operating expenses were principally due to an increase in operating activity. Additionally, $1.5 million of sales and use tax refunds reduced operating expenses in the fourth quarter of 2021, which were not available in 2022.
  - Depreciation and amortization in the Permian segment increased $14.6 million primarily due to depreciation from additional assets placed in service, including a $3.4 million increase associated with the Amarillo Rattler Acquisition in April 2021 and a $7.0 million increase associated with the transfer of equipment related to the Phantom and Warhorse processing facilities.
- *Louisiana Segment.*
  - Revenues and cost of sales, exclusive of operating expenses and depreciation and amortization, increased $1,437.6 million and $1,371.2 million, respectively, resulting in an increase in adjusted gross margin in the Louisiana segment of $66.4 million, due to:
    - A $31.3 million increase in adjusted gross margin associated with our Louisiana NGL transmission and fractionation assets. Adjusted gross margin, excluding derivative activity, decreased $8.1 million, which was primarily due to fluctuations in market prices. Derivative activity associated with our Louisiana NGL transmission and fractionation assets increased adjusted gross margin by $39.4 million, which included $38.0 million from increased realized gains and $1.4 million from increased unrealized gains.
    - A $40.9 million increase in adjusted gross margin associated with our Louisiana natural gas assets. Adjusted gross margin, excluding derivative activity, increased $27.8 million, which was primarily due to higher volumes from existing customers. Derivative activity associated with our Louisiana natural gas

assets increased adjusted gross margin by $13.1 million, which included $6.4 million from decreased realized losses and $6.7 million from increased unrealized gains.

- A $5.8 million decrease in adjusted gross margin associated with our ORV crude assets. Adjusted gross margin, excluding derivative activity, decreased $5.5 million, which was primarily due to unfavorable price spreads. Derivative activity associated with our ORV crude assets decreased adjusted gross margin by $0.3 million, which included $0.8 million from decreased realized losses and $1.1 million from decreased unrealized gains.

◦ Operating expenses in the Louisiana segment increased $17.0 million primarily due to a $10.4 million increase in utilities expense, a $2.6 million increase in construction fees and services, a $1.3 million increase in vehicle expenses, and a $1.0 million increase in materials and supplies expense. These increases in operating expenses were principally due to an increase in operating activity.

◦ Depreciation and amortization in the Louisiana segment increased $15.5 million primarily due to changes in estimated useful lives of certain non-core assets.

- *Oklahoma Segment.*

◦ Revenues and cost of sales, exclusive of operating expenses and depreciation and amortization, increased $398.8 million and $327.8 million, respectively, resulting in an increase in adjusted gross margin in the Oklahoma segment of $71.0 million, due to:

- A $72.2 million increase in adjusted gross margin associated with our Oklahoma natural gas assets. Adjusted gross margin, excluding derivative activity, increased $54.4 million, which was primarily due to higher volumes from existing customers. Derivative activity associated with our Oklahoma natural gas assets increased adjusted gross margin by $17.8 million, which included $9.7 million from decreased realized losses and $8.1 million from increased unrealized gains.
- A $1.2 million decrease in adjusted gross margin associated with our Oklahoma crude assets. Adjusted gross margin, excluding derivative activity, increased $1.5 million, which was primarily due to higher volumes from existing customers. Derivative activity associated with our Oklahoma crude assets decreased adjusted gross margin by $2.7 million, which included $0.2 million from decreased realized gains and $2.5 million from decreased unrealized gains.

◦ Operating expenses in the Oklahoma segment increased $10.9 million primarily due to a $4.4 million increase in materials and supplies expense, a $3.6 million increase in construction fees and services, and a $2.5 million increase in utilities expense. These increases in operating expenses were principally due to an increase in operating activity. Operating expenses also increased by $1.8 million due to the costs associated with the transfer of equipment to the Phantom processing facility.

◦ Depreciation and amortization in the Oklahoma segment decreased $2.5 million primarily due to a $4.8 million decrease from the transfer of equipment related to the Phantom and Warhorse processing facilities. This decrease was partially offset by a $2.3 million increase in depreciation from additional assets placed in service.

- *North Texas Segment.*

◦ Revenues and cost of sales, exclusive of operating expenses and depreciation and amortization, increased $161.3 million and $99.9 million, respectively, resulting in an increase in adjusted gross margin in the North Texas segment of $61.4 million. Adjusted gross margin, excluding derivative activity, increased $39.2 million, which was primarily due to the Barnett Shale Acquisition on July 1, 2022. Derivative activity associated with our North Texas segment increased adjusted gross margin by $22.2 million, which included $0.5 million from increased realized losses and $22.7 million from increased unrealized gains.

◦ Operating expenses in the North Texas segment increased $15.4 million primarily due to a $6.4 million increase in materials and supplies expense, a $2.0 million increase in ad valorem taxes, a $1.8 million increase in construction fees and services, a $1.5 million increase in utilities expense, and a $1.4 million increase in labor and benefits costs. These increases in operating expenses were principally due to an increase in operating activity from the Barnett Shale Acquisition in July 2022. Additionally, $1.3 million of sales and use tax refunds reduced operating expenses in the fourth quarter of 2021, which were not available in 2022.

- Depreciation and amortization in the North Texas segment increased $6.8 million primarily due to an $8.2 million increase in depreciation related to the Barnett Shale Acquisition in July 2022. This increase was partially offset by a $1.4 million decrease in depreciation from assets reaching the end of their depreciable lives.

- *Corporate Segment.*

  - Revenues and cost of sales, exclusive of operating expenses and depreciation and amortization, each increased $700.2 million. The corporate segment includes offsetting eliminations related to intercompany revenues and cost of sales, exclusive of operating expenses and depreciation and amortization.

  - Depreciation and amortization in the Corporate segment decreased $2.5 million primarily due to assets reaching the end of their depreciable lives.

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.

Valuation and 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. Management’s estimate of future cash flows is subject to uncertainty due to the changing business environment, volatility of commodity prices, and a number of other factors that are beyond our ability to consistently predict. Management updates their estimated future cash flows throughout the year and a potential impairment is highly sensitive to unfavorable changes in the underlying estimated cash flows. 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.”

Liquidity and Capital Resources

Cash Flows from Operating Activities. Net cash provided by operating activities was $1,222.7 million for the year ended December 31, 2023 compared to $1,049.3 million for the year ended December 31, 2022. Operating cash flows before working capital and changes in working capital for the comparative periods were as follows (in millions):

	Year Ended December 31,	
	2023	2022
Operating cash flows before working capital	$ 1,138.5	$ 1,100.9
Changes in working capital	84.2	(51.6)

Operating cash flows before changes in working capital increased $37.6 million for the year ended December 31, 2023 compared to the year ended December 31, 2022. The primary contributor to the increase in operating cash flows before working capital is as follows:

- Gross margin, excluding depreciation and amortization, non-cash commodity derivative activity, utility credits redeemed or earned, and unit-based compensation, increased $60.2 million. The increase in gross margin is due to a $125.1 million increase in adjusted gross margin, excluding non-cash commodity derivative activity, which was partially offset by a $64.9 million increase in operating expenses, excluding utility credits redeemed or earned and unit-based compensation. For more information regarding the changes in gross margin for the year ended December 31, 2023 compared to the year ended December 31, 2022, see "Results of Operations."

This increase was partially offset by a $27.7 million increase in interest expense, net of interest income, excluding amortization of debt issue costs and net discounts.

The changes in working capital for the year ended December 31, 2023 compared to the year ended December 31, 2022 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 purchases.

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 income during 2024 that will be offset by net operating loss carryforwards, and as a result, we do not expect to incur material amounts of federal and state income tax liabilities. When we 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 8" for additional information.

Cash Flows from Investing Activities. Net cash used in investing activities was $440.5 million for the year ended December 31, 2023 compared to $773.0 million for the year ended December 31, 2022. Our primary investing activities consisted of the following (in millions):

	Year Ended December 31,	
	2023	2022
Additions to property and equipment (1)	$ (445.7)	$ (332.5)
Acquisitions, net of cash acquired (2)	—	(390.3)
Contributions to unconsolidated affiliate investments (3)	(68.1)	(65.9)
Proceeds from disposition of assets (4)	73.1	12.8

(1) The increase in capital expenditures was due to expansion projects to accommodate increased volumes on our systems.
(2) Represents cash paid for the Barnett Shale Acquisition in July 2022 and the Central Oklahoma Acquisition in December 2022.
(3) Represents contributions to the Matterhorn JV and GCF. See "Item 8. Financial Statements and Supplementary Data—Note 11" for more information regarding the contributions to unconsolidated affiliate investments.
(4) Primarily relates to the divestitures of our ORV assets in our Louisiana segment in November 2023 and the sale of compressor units associated with our ORV assets in December 2022. See "Item 8. Financial Statements and Supplementary Data—Note 3" for additional information on the divestitures of our ORV assets in our Louisiana segment in November 2023.

Cash Flows from Financing Activities. Net cash used in financing activities was $776.1 million for the year ended December 31, 2023 compared to $279.9 million for the year ended December 31, 2022. Our primary financing activities consisted of the following (in millions):

	Year Ended December 31,	
	2023	2022
Net borrowings (repayments) on the AR Facility (1)	$ (200.0)	$ 150.0
Net borrowings (repayments) on the Revolving Credit Facility (1)	(255.0)	240.0
Net borrowings on ENLC's senior unsecured notes (1)	297.0	700.0
Net repurchases of ENLK's senior unsecured notes (1)	—	(727.8)
Payment of installment payable for Amarillo Rattler Acquisition (2)	—	(10.0)
Payment of inactive easement commitment (3)	—	(10.0)
Distributions to members	(236.2)	(221.4)
Distributions to Series B Preferred Unitholders (4)	(63.1)	(70.4)
Distributions to Series C Preferred Unitholders (4)	(35.7)	(23.4)
Distributions to joint venture partners (5)	(73.8)	(69.1)
Payment to redeem mandatorily redeemable non-controlling interest (6)	(10.5)	—
Redemption of Series B Preferred Units (4)	—	(50.5)
Repurchases of Series C Preferred Units (4)	(13.1)	(15.2)
Contributions from non-controlling interests (7)	69.5	32.9
Common unit repurchases (8)	(234.8)	(175.0)
Conversion of unit-based awards for common units, net of units withheld for taxes	(19.6)	(16.1)

(1) See "Item 8. Financial Statements and Supplementary Data—Note 7" for more information regarding the AR Facility, the Revolving Credit Facility, and the issuance of new senior unsecured notes by us and repurchases of ENLK's senior unsecured notes.
(2) Consideration for the Amarillo Rattler Acquisition included an installment payable, which was paid on April 30, 2022.
(3) Amount related to an inactive easement commitment, which was paid in August 2022.
(4) See "Item 8. Financial Statements and Supplementary Data—Note 9" for information on distributions to holders of the Series B Preferred Units and Series C Preferred Units and information on the partial redemption of the Series B Preferred Units and the repurchases of the Series C Preferred Units.
(5) Represents distributions to NGP for its ownership in the Delaware Basin JV and distributions to Marathon Petroleum Corporation for its ownership in the Ascension JV.
(6) In January 2023, we settled the redemption of the mandatorily redeemable non-controlling interest in one of our non-wholly owned subsidiaries. See "Item 8. Financial Statements and Supplementary Data—Note 2" for more information regarding the redemption.
(7) Represents contributions from NGP to the Delaware Basin JV.
(8) See "Item 8. Financial Statements and Supplementary Data—Note 10" for more information regarding our common unit repurchase program.

Capital Requirements

As of December 31, 2023, the following table summarizes our expected capital requirements for 2024 (in millions):

Capital expenditures, net to ENLC (1)	$ 435
Operating expenses associated with the relocation of processing facilities, net to ENLC (2)	15
Contributions to unconsolidated affiliate investments (3)	10
Total	$ 460

(1) Excludes capital expenditures that are contributed by other entities and relate to the non-controlling interest share of our consolidated entities.
(2) Represents cost incurred to execute discrete, project-based strategic initiatives aimed at realigning available processing capacity from our Oklahoma and North Texas segments to the Permian segment. These costs are not part of our ongoing operations. These costs exclude amounts that are contributed by other entities and relate to the non-controlling interest share of our consolidated entities.
(3) Includes contributions made to our GCF investment and the Matterhorn JV.

Our primary capital projects for 2024 include the relocation of the Cowtown processing plant, CCS-related initiatives, contributions to unconsolidated affiliate investments, continued development of our existing systems through well connects, and other low-cost development projects. We expect to fund our 2024 capital requirements from operating cash flows.

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, to make contributions to unconsolidated affiliate investments, 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, 2023 and 2022.

Total Contractual Cash Obligations. A summary of our total contractual cash obligations as of December 31, 2023 is as follows (in millions):

	Payments Due by Period						
	Total	2024	2025	2026	2027	2028	Thereafter
ENLC's & ENLK's senior unsecured notes	$ 4,309.2	$ 97.9	$ 421.6	$ 491.0	$ —	$ 500.0	$ 2,798.7
AR Facility (1)	300.0	—	300.0	—	—	—	—
Revolving Credit Facility (1)(2)	—	—	—	—	—	—	—
Interest payable on fixed long-term debt obligations (1)	2,359.6	233.0	222.1	213.3	189.5	175.4	1,326.3
Acquisition contingent consideration (3)	6.7	0.3	1.2	4.9	0.3	—	—
Repurchase of ENLC common units held by GIP (4)	41.5	41.5	—	—	—	—	—
Operating lease obligations	123.8	31.8	24.4	15.2	9.1	8.7	34.6
Purchase obligations	9.9	9.9	—	—	—	—	—
Pipeline and trucking capacity and deficiency agreements (5)	929.5	94.5	113.4	100.1	88.0	84.9	448.6
Total contractual obligations	$ 8,080.2	$ 508.9	$ 1,082.7	$ 824.5	$ 286.9	$ 769.0	$ 4,608.2

(1) The interest payable related to the Revolving Credit Facility and the AR Facility is not reflected in the table because such amounts depend on the outstanding balances and interest rates of the Revolving Credit Facility and the AR Facility, which vary from time to time. See "Item 8. Financial Statements and Supplementary Data—Note 7" for more information regarding the Revolving Credit Facility and the AR Facility.
(2) As of December 31, 2023, there were no amounts outstanding under the Revolving Credit Facility.
(3) The estimated fair value of the contingent consideration for the Amarillo Rattler Acquisition and the Central Oklahoma Acquisition was calculated in accordance with the fair value guidance contained in ASC 820. There are a number of assumptions and estimates factored into these fair values and actual contingent consideration payments could differ from these estimated fair values. See "Item 8. Financial Statements and Supplementary Data—Note 14" for additional information.
(4) Relates to the repurchase of ENLC common units held by GIP on February 19, 2024. See "Item 8. Financial Statements and Supplementary Data—Note 10" for more information.
(5) Consists of pipeline capacity payments for firm transportation and deficiency agreements.

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.

Our contractual cash obligations for 2024 are expected to be funded from cash flows generated from our operations.

Indebtedness

Revolving Credit Facility. As of December 31, 2023, there were no outstanding borrowings and $26.7 million in outstanding letters of credit under the Revolving Credit Facility.

AR Facility. As of December 31, 2023, the AR Facility had a borrowing base of $404.2 million and there were $300.0 million in outstanding borrowings under the AR Facility. In connection with the AR Facility, certain subsidiaries of ENLC 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.

Senior Unsecured Notes. As of December 31, 2023, we had $4.3 billion in aggregate principal amount of outstanding senior unsecured notes maturing from 2024 to 2047, of which $97.9 million matures on April 1, 2024 and is classified as "Current maturities of long-term debt" on the consolidated balance sheet.

Guarantees. The amounts outstanding on our senior unsecured notes and the Revolving Credit Facility are guaranteed in full by our subsidiary ENLK, including 105% of any letters of credit outstanding under the Revolving 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 and the Revolving Credit Facility. Liabilities under the guarantees rank equally in right of payment with all existing and future senior unsecured indebtedness of ENLK.

ENLC's 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 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, 2023, ENLC records, on a stand-alone basis, transactions that do not occur at ENLK, which are primarily related to the taxation of ENLC and the elimination of intercompany borrowings.

See "Item 8. Financial Statements and Supplementary Data—Note 7" for more information on our outstanding debt.

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

See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Recent Developments Affecting Industry Conditions and Our Business—Inflation" for more information.

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 substantial 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 15."

Recent Accounting Pronouncements

We have reviewed recently issued accounting pronouncements that became effective during the year ended December 31, 2023 and have determined that none had a material impact to our consolidated financial statements.

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," "shall," "should," "plan," "predict," "anticipate," "intend," "estimate," "expect," "continue," and similar expressions. Such forward-looking statements include, but are not limited to, statements about future results and growth of our CCS business, expected financial and operational results associated with certain projects, acquisitions, or growth capital expenditures, timing for completion of construction or expansion projects, results in certain basins, profitability, financial or leverage metrics, cost savings or operational, environmental and climate change initiatives, our future capital structure and credit ratings, objectives, strategies, expectations, and intentions, the impact of weather related events 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 operations, or cash flows, include, without limitation, (a) potential conflicts of interest of GIP with us and the potential for GIP to favor GIP's own interests to the detriment of our unitholders, (b) GIP's ability to compete with us and the fact that it is not required to offer us the opportunity to acquire additional assets or businesses, (c) a default under GIP's credit facility or a change in control of GIP 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, (d) the dependence on key customers for a substantial portion of the natural gas and crude that we gather, process, and transport, (e) developments that materially and adversely affect our key customers or other customers, (f) adverse developments in the midstream business that may reduce our ability to make distributions, (g) competition for crude oil, condensate, natural gas, and NGL supplies and any decrease in the availability of such commodities, (h) decreases in the volumes that we gather, process, fractionate, or transport, (i) increasing scrutiny and changing expectations from stakeholders with respect to our environment, social, and governance practices, (j) our ability to receive or renew required permits and other approvals, (k) increased federal, state, and local legislation, and regulatory initiatives, as well as government reviews relating to hydraulic fracturing resulting in increased costs and reductions or delays in natural gas production by our customers, (l) climate change legislation and regulatory initiatives resulting in increased operating costs and reduced demand for the natural gas and NGL services we provide, (m) changes in the availability and cost of capital, (n) volatile prices and market demand for crude oil, condensate, natural gas, and NGLs that are beyond our control, (o) our debt levels could limit our flexibility and adversely affect our financial health or limit our flexibility to obtain financing and to pursue other business opportunities, (p) operating hazards, natural disasters, weather-related issues or delays, casualty losses, and other matters beyond our control, (q) reductions in demand for NGL products by the petrochemical, refining, or other industries or by the fuel markets, (r) impairments to goodwill, long-lived assets and equity method investments, (s) construction risks in our major development projects, (t) challenges we may face in connection with our strategy to build a CCS transportation business and to enter into other new lines of business related to the energy transition, including entry into the CCS business, (u) our ability to effectively integrate and manage assets we acquire through acquisitions, and (v) 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 and equity.

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.

The legislation and potential new regulations may also require counterparties to our derivative instruments to spin off or result in such counterparties spinning off some of their derivative 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 2023. Crude oil prices decreased 11%, weighted average NGL prices decreased 21%, and natural gas prices decreased 44% from January 1, 2023 to December 31, 2023. The table below shows the range of closing prices for crude oil, NGL, and natural gas during 2023.

Commodity	Closing Price		Date
Crude oil (high) (1)	$	93.68	September 27, 2023
Crude oil (low) (1)	$	66.74	March 17, 2023
Crude oil (average) (1)(4)	$	77.60	—
NGL (high) (2)	$	0.69	January 19, 2023
NGL (low) (2)	$	0.34	June 12, 2023
NGL (average) (2)(4)	$	0.50	—
Natural gas (high) (3)	$	4.17	January 4, 2023
Natural gas (low) (3)	$	1.99	March 29, 2023
Natural gas (average) (3)(4)	$	2.66	—

(1) Crude oil closing prices based on the NYMEX futures daily close prices.
(2) Weighted average NGL 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 natural 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 also subject to direct risks due to fluctuations in commodity prices. While approximately 90% of our adjusted gross margin for the year ended December 31, 2023 was generated from arrangements with fee-based structures with minimal direct commodity price exposure, the remainder is subject to more direct commodity price exposure. Our exposure to these commodity price fluctuations is primarily in the natural gas processing component of our business.

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

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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.

Commodity derivatives 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 NGLs, natural gas, crude, and condensate.

The following table sets forth information related to derivative instruments outstanding at December 31, 2023.

riod	Underlying	Notional Volume (Net Position)	Reference Price	Price Range		Net Fair Value Asset/(Liability) (In Millions)
uary 2024 - February 2024	Ethane	(5.3) MMgals	OPIS Mt Belvieu	$0.19 - $0.26/Gal	$	0.1
uary 2024 - December 2024	Propane	(93.7) MMgals	OPIS Mt Belvieu	$0.61 - $0.85/Gal		0.6
uary 2024 - September 2024	Normal Butane	(12.2) MMgals	OPIS Mt Belvieu	$0.71 - $0.91/Gal		(1.5)
uary 2024	Natural Gasoline	(0.6) MMgals	NYMEX WTI Average	$1.57 - $1.75/Gal		—
uary 2024 - December 2024	Natural Gasoline & Condensate	58.0 MMgals	OPIS Mt Belvieu and NYMEX WTI Average differential	($0.33) - ($0.24)/Gal		1.1
uary 2024 - January 2028	Natural Gas	(12.3) Bbtu	NYMEX Henry Hub	$2.13- $6.19/MMbtu		11.9
uary 2024 - December 2024	Natural Gas	(3.1) Bbtu	Waha basis differential	($1.13) - ($0.22)/MMbtu		(0.8)
uary 2024	Natural Gas	0.3 Bbtu	Henry Hub Gas Daily	$2.59 - $2.64/MMbtu		—
uary 2024	Natural Gas	0.6 Bbtu	NGPL TEXOK Gas Daily	$2.42 - $2.42/MMbtu		—
uary 2024 - December 2024	Natural Gas	(8.9) Bbtu	NGPL TEXOK Basis differential	($0.27) - ($0.25)/MMbtu		—
ruary 2024 - December 2024	Crude and Condensate	(0.4) MMbbls	NYMEX WTI	$69.27 - $80.77/Bbl		1.1
ruary 2024 - December 2025	Crude and Condensate	(6.9) MMbbls	WTI-Houston and Midland basis differential	$0.70 - $0.90/Bbl		1.1
otal fair value of commodity derivatives					$	13.6

Another price risk we face is the risk of mismatching volumes of natural 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, 2023, our outstanding commodity derivative instruments had a net fair value asset of $13.6 million. The aggregate effect of a hypothetical 10% change, increase or decrease, in natural gas, crude and condensate, and NGL prices would result in a change of approximately $18.8 million in the net fair value of these contracts as of December 31, 2023.

Interest Rate Risk

We are exposed to interest rate risk on the Revolving Credit Facility and the AR Facility. Amounts drawn on the Revolving Credit Facility and the AR Facility bear interest at rates based on SOFR. At December 31, 2023, we had no outstanding borrowings under the Revolving Credit Facility and $300.0 million in outstanding borrowings under the AR Facility.

In January 2023, we entered into a $400.0 million interest rate swap to reduce the variability of cash outflows associated with our floating-rate, SOFR-based borrowings, including borrowings on the Revolving Credit Facility and the AR Facility. This swap has been designated as a cash flow hedge. See “Item 8. Financial Statements and Supplementary Data—Note 13” for more information on our outstanding derivatives.

A 1.0% increase or decrease in interest rates would change our annualized interest expense by approximately $3.0 million for the AR Facility, based on our outstanding borrowings at December 31, 2023. This change in interest expense would be offset by a $4.0 million change in the opposite direction due to our open interest rate swap hedge.

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, 2029, and 2030 as these are fixed-rate obligations. As of December 31, 2023, the estimated fair value of the senior unsecured notes was approximately $4,127.0 million, based on the market prices of ENLK’s and our publicly traded debt at December 31, 2023. 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 $232.7 million decrease in fair value of the senior unsecured notes at December 31, 2023. See “Item 8. Financial Statements and Supplementary Data—Note 7” for more information on our outstanding indebtedness.

Prior to December 15, 2022, distributions on ENLK’s Series C Preferred Units were based on a fixed interest rate. Beginning with the interest period which commenced on December 15, 2022, distributions on ENLK’s Series C Preferred Units were based on a floating rate tied to LIBOR plus a spread of 4.11%. As a result of the floating rate, the amount paid by ENLK for distributions became more sensitive to changes in interest rates. Beginning with the interest period which commenced on September 15, 2023, distributions are based on the forward-looking term rate based on SOFR (“Term SOFR”), plus a Term SOFR spread adjustment of 0.26161%, plus a spread of 4.11%. See “Item 8. Financial Statements and Supplementary Data—Note 9” for more information regarding distributions with respect to the Series C Preferred Units.

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 GAAP.

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 GAAP, 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, 2023, 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, 2023, 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 GAAP.

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, 2023 and 2022, the related consolidated statements of operations, comprehensive income, changes in members' equity, and cash flows for each of the years in the three-year period ended December 31, 2023, 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, 2023, 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, 2023 and 2022, and the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2023, 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, 2023 based on criteria established in Internal Control – Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission.

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.

Evaluation of long-lived assets for impairment triggering events

As discussed in Note 2 to the consolidated financial statements, the Company evaluates property, plant, and equipment and intangible assets (collectively, long-lived assets) for potential impairment whenever events or changes in circumstances indicate that their carrying value may not be recoverable (triggering events). Triggering events include significant changes in the use of the asset group, current and/or historical operating results that are significantly less than forecasted results, negative industry or economic trends including changes in commodity prices, significant adverse changes in legal or regulatory factors, or an expectation that it is more likely than not that an asset group will be sold before the end of its useful life. The carrying value of property, plant, and equipment and intangible assets as of December 31, 2023 was $6.41 billion and $0.79 billion, respectively.

We identified the evaluation of long-lived assets for impairment triggering events as a critical audit matter. A higher degree of subjective auditor judgment was required to evaluate the impact of forecasted prices for oil, natural gas, and natural gas liquids (NGL) on the recoverability of the Company's long-lived assets as sustained declines in commodity prices could result in decreases in volumes gathered, processed, fractionated, and transported by the Company.

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 process to evaluate triggering events related to the impairment of long-lived assets. This included controls related to the Company's selection of forecasted prices for oil, natural gas, and NGL and the identification and assessment of the potential impacts of such prices on oil, natural gas, and NGL volumes available to the Company. We examined the Company's analysis of potential triggering events for long-lived assets and evaluated the Company's responses to the factors identified by inspecting publicly available information regarding rig counts and producer drilling outlook. We involved valuation professionals with specialized skills and knowledge, who assisted in evaluating the forecasted prices for oil, natural gas, and NGL used in the Company's analysis by comparing such prices to commodity price curves prepared by third parties.

/s/ KPMG LLP

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

Dallas, Texas
February 21, 2024

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

	December 31, 2023	December 31, 2022
ASSETS		
Current assets:		
Cash and cash equivalents	$ 28.7	$ 22.6
Accounts receivable:		
Trade receivables (1)	85.9	89.2
Accrued revenue and other	581.4	636.0
Fair value of derivative assets	76.9	68.4
Other current assets	65.4	166.6
Total current assets	838.3	982.8
Property and equipment, net of accumulated depreciation of $5,137.2 and $4,774.5, respectively	6,407.0	6,556.0
Intangible assets, net of accumulated amortization of $1,051.2 and $923.6, respectively	793.6	921.2
Investment in unconsolidated affiliates	150.5	90.2
Fair value of derivative assets	27.0	2.9
Other assets, net	112.2	97.9
Total assets	$ 8,328.6	$ 8,651.0
LIABILITIES AND MEMBERS' EQUITY		
Current liabilities:		
Accounts payable and drafts payable	$ 126.5	$ 126.9
Accrued natural gas, NGLs, condensate, and crude oil purchases	428.0	476.0
Fair value of derivative liabilities	62.7	42.9
Current maturities of long-term debt	97.9	—
Other current liabilities	278.5	229.6
Total current liabilities	993.6	875.4
Long-term debt, net of unamortized issuance cost	4,471.0	4,723.5
Other long-term liabilities	98.0	94.0
Deferred tax liability, net	104.2	42.7
Fair value of derivative liabilities	26.7	2.7
Members' equity:		
Members' equity (451,614,086 and 468,980,630 units issued and outstanding, respectively)	1,000.5	1,306.4
Accumulated other comprehensive income	0.7	—
Non-controlling interest	1,633.9	1,606.3
Total members' equity	2,635.1	2,912.7
Commitments and contingencies (Note 15)		
Total liabilities and members' equity	$ 8,328.6	$ 8,651.0

(1) There was no allowance for bad debt at December 31, 2023. Includes allowance for bad debt of $0.1 million at December 31, 2022.

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,		
	2023	**2022**	**2021**
Revenues:			
Product sales	$ 5,755.6	$ 8,564.9	$ 5,994.0
Midstream services	1,123.8	962.9	851.0
Gain (loss) on derivative activity	20.7	14.3	(159.1)
Total revenues	6,900.1	9,542.1	6,685.9
Operating costs and expenses:			
Cost of sales, exclusive of operating expenses and depreciation and amortization	4,856.1	7,572.8	5,189.9
Operating expenses	558.2	524.9	362.9
Depreciation and amortization	657.1	639.4	607.5
Impairments	20.7	—	0.8
(Gain) loss on disposition of assets	(0.3)	18.0	(1.5)
General and administrative	115.5	125.2	107.8
Total operating costs and expenses	6,207.3	8,880.3	6,267.4
Operating income	692.8	661.8	418.5
Other income (expense):			
Interest expense, net of interest income	(271.7)	(245.0)	(238.7)
Loss on extinguishment of debt	—	(6.2)	—
Loss from unconsolidated affiliate investments	(8.2)	(5.6)	(11.5)
Other income (expense)	(0.1)	0.8	—
Total other expense	(280.0)	(256.0)	(250.2)
Income before non-controlling interest and income taxes	412.8	405.8	168.3
Income tax benefit (expense)	(62.8)	94.9	(25.4)
Net income	350.0	500.7	142.9
Net income attributable to non-controlling interest	143.8	139.4	120.5
Net income attributable to ENLC	$ 206.2	$ 361.3	$ 22.4
Net income attributable to ENLC per unit:			
Basic common unit	$ 0.45	$ 0.76	$ 0.05
Diluted common unit	$ 0.44	$ 0.74	$ 0.05

See accompanying notes to consolidated financial statements.

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

	Year Ended December 31,		
	2023	**2022**	**2021**
Net income	$ 350.0	$ 500.7	$ 142.9
Unrealized gain on designated cash flow hedge (1)	0.7	1.4	13.9
Comprehensive income	350.7	502.1	156.8
Comprehensive income attributable to non-controlling interest	143.8	139.4	120.5
Comprehensive income attributable to ENLC	$ 206.9	$ 362.7	$ 36.3

(1) Includes tax expense of $0.2 million, $0.5 million, and $4.3 million for the years ended December 31, 2023, 2022, and 2021, 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 Income (Loss)	Non-Controlling Interest	Total	Redeemable Non-controlling interest (Temporary Equity)
	$	Units	$	$	$	$
Balance, December 31, 2020	$ 1,508.8	489.4	$ (15.3)	$ 1,719.5	$ 3,213.0	$ —
Conversion of unit-based awards for common units, net of units withheld for taxes	(2.0)	1.0	—	—	(2.0)	—
Unit-based compensation	23.6	—	—	—	23.6	—
Contributions from non-controlling interests	—	—	—	3.2	3.2	—
Distributions	(186.8)	—	—	(130.6)	(317.4)	(0.2)
Unrealized gain on designated cash flow hedge (1)	—	—	13.9	—	13.9	—
Fair value adjustment related to redeemable non-controlling interest	(0.1)	—	—	—	(0.1)	0.2
Redemption of Series B Preferred Units	—	—	—	(50.0)	(50.0)	—
Common units repurchased	(40.1)	(6.1)	—	—	(40.1)	—
Net income	22.4	—	—	120.5	142.9	—
Balance, December 31, 2021	1,325.8	484.3	(1.4)	1,662.6	2,987.0	—
Conversion of unit-based awards for common units, net of units withheld for taxes	(16.1)	3.1	—	—	(16.1)	—
Unit-based compensation	31.8	—	—	—	31.8	—
Contributions from non-controlling interests	—	—	—	32.9	32.9	—
Distributions	(221.4)	—	—	(162.9)	(384.3)	—
Unrealized gain on designated cash flow hedge (2)	—	—	1.4	—	1.4	—
Redemption of Series B Preferred Units	—	—	—	(50.5)	(50.5)	—
Repurchase of Series C Preferred Units	—	—	—	(15.2)	(15.2)	—
Common units repurchased	(175.0)	(18.4)	—	—	(175.0)	—
Net income	361.3	—	—	139.4	500.7	—
Balance, December 31, 2022	$ 1,306.4	469.0	$ —	$ 1,606.3	$ 2,912.7	$ —

(1) Includes tax expense of $4.3 million.
(2) Includes tax expense of $0.5 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 Income (Loss)	Non-Controlling Interest	Total
	$	Units	$	$	$
Balance, December 31, 2022	$ 1,306.4	469.0	$ —	$ 1,606.3	$ 2,912.7
Conversion of unit-based awards for common units, net of units withheld for taxes	(19.6)	3.0	—	—	(19.6)
Unit-based compensation	19.2	—	—	—	19.2
Contributions from non-controlling interests	—	—	—	69.5	69.5
Distributions	(236.2)	—	—	(172.6)	(408.8)
Unrealized gain on designated cash flow hedge (1)	—	—	0.7	—	0.7
Adjustment related to the redemption of the mandatorily redeemable non-controlling interest (2)	0.8	—	—	—	0.8
Repurchase of Series C Preferred Units	—	—	—	(13.1)	(13.1)
Common units repurchased	(234.8)	(20.4)	—	—	(234.8)
Accrued common unit repurchase (3)	(41.5)	—	—	—	(41.5)
Net income	206.2	—	—	143.8	350.0
Balance, December 31, 2023	$ 1,000.5	451.6	$ 0.7	$ 1,633.9	$ 2,635.1

(1) Includes tax expense of $0.2 million.
(2) Relates to book-to-tax differences recorded upon the settlement of the mandatorily redeemable non-controlling interest.
(3) Relates to the repurchase of ENLC common units held by GIP, which are contractually subject to repurchase by ENLC at the end of each quarter and settled in the subsequent quarter. As of December 31, 2023, we accrued $41.5 million in connection with the repurchase of ENLC common units held by GIP. For additional information, see "Note 10—Members' Equity."

See accompanying notes to consolidated financial statements.

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

	Year Ended December 31,		
	2023	**2022**	**2021**
Cash flows from operating activities:			
Net income	$ 350.0	$ 500.7	$ 142.9
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	657.1	639.4	607.5
(Gain) loss on disposition of assets	(0.3)	18.0	(1.5)
Non-cash unit-based compensation	19.2	30.4	25.3
Utility credits redeemed (earned)	1.5	31.1	(32.6)
Non-cash (gain) loss on derivatives recognized in net income	12.1	(38.3)	10.3
Loss on extinguishment of debt	—	6.2	—
Amortization of debt issuance costs and net discount of senior unsecured notes	6.4	5.5	5.2
Amortization of designated cash flow hedge	—	1.9	12.5
Deferred income tax expense (benefit)	62.1	(95.3)	24.6
Loss from unconsolidated affiliate investments	8.2	5.6	11.5
Impairments	20.7	—	0.8
Other operating activities	1.5	(4.3)	(4.0)
Changes in assets and liabilities, net of the effects of acquisitions:			
Accounts receivable, accrued revenue, and other	58.2	102.4	(259.9)
Product inventory, prepaid expenses, and other	97.0	(115.0)	(13.6)
Accounts payable, accrued product purchases, and other accrued liabilities	(71.0)	(39.0)	328.3
Net cash provided by operating activities	1,222.7	1,049.3	857.3
Cash flows from investing activities:			
Additions to property and equipment	(445.7)	(332.5)	(184.0)
Acquisitions, net of cash acquired	—	(390.3)	(56.7)
Proceeds from disposition of assets	73.1	12.8	4.8
Contributions to unconsolidated affiliate investments	(68.1)	(65.9)	—
Other investing activities	0.2	2.9	4.5
Net cash used in investing activities	(440.5)	(773.0)	(231.4)
Cash flows from financing activities:			
Proceeds from borrowings	2,843.4	4,911.5	1,234.5
Repayments on borrowings	(3,001.4)	(4,549.3)	(1,469.5)
Payment of installment payable for the Amarillo Rattler Acquisition	—	(10.0)	—
Payment of inactive easement commitment	—	(10.0)	—
Distributions to members	(236.2)	(221.4)	(186.8)
Distributions to non-controlling interests	(172.6)	(162.9)	(130.8)
Payment to redeem mandatorily redeemable non-controlling interest	(10.5)	—	—
Redemption of Series B Preferred Units	—	(50.5)	(50.0)
Repurchases of Series C Preferred Units	(13.1)	(15.2)	—
Contributions from non-controlling interests	69.5	32.9	3.2
Common unit repurchases	(234.8)	(175.0)	(40.1)
Conversion of unit-based awards for common units, net of units withheld for taxes	(19.6)	(16.1)	(2.0)
Other financing activities	(0.8)	(13.9)	2.2
Net cash used in financing activities	(776.1)	(279.9)	(639.3)
Net increase (decrease) in cash and cash equivalents	6.1	(3.6)	(13.4)
Cash and cash equivalents, beginning of period	22.6	26.2	39.6
Cash and cash equivalents, end of period	$ 28.7	$ 22.6	$ 26.2

See accompanying notes to consolidated financial statements.

(1) Organization and Nature of Business

(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." As of December 31, 2023, GIP, through GIP III Stetson I, L.P. and GIP III Stetson II, L.P, owns 46.2% of the outstanding limited liability company interests in ENLC. In addition to GIP's equity interests in ENLC, GIP III Stetson I, L.P. maintains control over the Managing Member through its ownership of all the equity interests in the Managing Member. ENLC owns all of ENLK's common units and also owns all of the membership interests of the General Partner. The General Partner manages ENLK's operations and activities.

(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, storing, trans-loading, and selling crude oil and condensate.

As of December 31, 2023, our midstream energy asset network includes approximately 13,600 miles of pipelines, 25 natural gas processing plants with approximately 5.8 Bcf/d of processing capacity, seven fractionators with approximately 316,300 Bbls/d of fractionation capacity, barge and rail terminals, product storage facilities, purchasing and marketing capabilities, 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 gathering 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 diameter pipelines for further transmission. Our processing plants 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. We also store natural gas and NGLs on behalf of third parties for a fee or to balance our own purchases and sales in marketing natural gas and NGLs for our customers.

Our large diameter natural gas transmission pipelines provide access to multiple domestic production basins to a variety of customers, such as industrial end-users, LNG facilities, and utilities. Our large diameter natural gas transmission pipelines are connected to our gathering systems or third party gathering systems, natural gas transmission pipeline systems, and natural gas storage caverns.

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 we transport NGLs from our West Texas and Central Oklahoma operations on third party pipelines 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, in addition to condensate stabilization. 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.

(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. Certain reclassifications were made to the financial statements for the prior period to conform to current period presentation. The effect of these reclassifications had no impact on previously reported members’ equity or net income.

(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 natural 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

The following table summarizes the contractually committed fees (in millions) 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. Under these agreements, our customers or suppliers agree to transport or process a minimum volume of commodities on our system over an agreed period. If a customer or supplier fails to meet the minimum volume specified in such agreement, the customer or supplier is obligated to pay a contractually determined fee based upon the shortfall between actual volumes and the contractually stated volumes. 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. We record revenue under MVC and firm transportation contracts during periods of shortfall when it is known that the customer cannot, or will not, make up the deficiency. These fees do not represent the shortfall amounts we expect to collect under our MVC and firm transportation contracts, as we generally do not expect volume shortfalls to equal the full amount of the contractual MVCs and firm transportation contracts during these periods.

Contractually Committed Fees	**Commitments**
2024	$ 145.0
2025	126.2
2026	126.6
2027	105.9
2028	97.1
Thereafter	1,032.9
Total	$ 1,633.7

(d) Imbalance Accounting

Quantities of natural gas, NGLs, or crude and condensate 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, NGLs, or crude and condensate. We had imbalance payables of $6.3 million and $17.3 million at December 31, 2023 and 2022, respectively, which approximate the fair value of these imbalances. We had imbalance receivables of $8.0 million and $20.2 million at December 31, 2023 and 2022, 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 natural gas, NGLs, condensate, and crude oil purchases,” respectively, on the consolidated balance sheets.

(e) Cash and Cash Equivalents

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

(f) Income Taxes

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

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

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

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

(h) Property and Equipment

Property and equipment are stated at historical cost less accumulated depreciation. Assets acquired in a business combination are recorded at fair value. 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.

The components of property and equipment, net of accumulated depreciation are as follows (in millions):

	Year Ended December 31,	
	2023	2022
Transmission assets	$ 1,459.5	$ 1,452.0
Gathering systems	5,472.4	5,370.0
Natural gas processing plants and fractionation facilities	4,279.1	4,237.8
Other property and equipment	90.1	165.0
Construction in process	243.1	105.7
Property and equipment	11,544.2	11,330.5
Accumulated depreciation	(5,137.2)	(4,774.5)
Property and equipment, net of accumulated depreciation	$ 6,407.0	$ 6,556.0

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
Natural gas processing plants and fractionation facilities	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 years ended December 31, 2023, 2022, and 2021, dispositions primarily related to the sale of certain non-core assets. The (gain) loss on disposition of assets is as follows (in millions):

	Year Ended December 31,		
	2023	2022	2021
Net book value of assets disposed	$ 72.9	$ 30.8	$ 3.3
Proceeds from sales	(73.1)	(12.8)	(4.8)
Insurance recoveries	(0.1)	—	—
(Gain) loss on disposition of assets	$ (0.3)	$ 18.0	$ (1.5)

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, or triggering events, indicate that their carrying value may not be recoverable. Triggering events include, but are not limited to, significant changes in the use of the asset group, current operating results that are significantly less than forecasted results, and negative industry or economic trends, including changes in commodity prices, significant adverse changes in legal or regulatory factors, or an expectation that it is more likely than not that an asset group will be sold before the end of its useful life. 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 estimated volume of natural gas, NGLs, crude oil, and condensate available 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 or demand for our products 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 key customers, producers, and transporters of natural gas, NGLs, crude oil, and condensate; and
- competition from other midstream companies, including major energy companies.

We recognized impairment expense related to property and equipment as follows (in millions):

	Year Ended December 31,		
	2023	2022	2021
Property and equipment impairment (1)	$ 20.7	$ —	$ 0.6

(1) During the third quarter of 2023, we identified changes in our outlook for future cash flows and the anticipated use of certain ORV crude assets in our Louisiana segment. We determined that the carrying amounts of these assets exceeded their fair values, based on market inputs and certain assumptions.

(i) Comprehensive Income (Loss)

Comprehensive income (loss) is comprised 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 13—Derivatives.”

(j) Equity Method of Accounting

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

We evaluate our unconsolidated affiliate investments for potential impairment whenever events or changes in circumstances indicate that the carrying amount of the investments may not be recoverable. We recognize impairments of our investments as a loss from unconsolidated affiliates on our consolidated statements of operations.

For additional information, see “Note 11—Investment in Unconsolidated Affiliates.”

(k) 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, 2023, 2022, and 2021 are comprised of Series B Preferred Units, Series C Preferred Units, NGP’s 49.9% share of the Delaware Basin JV, and Marathon Petroleum Corporation’s 50.0% share of the Ascension JV.

Certain of our joint venture arrangements provide our joint venture partners with the right, under certain circumstances, to cause us to purchase their interest in the joint venture or to seek to sell the entire joint venture. For example, at any time after

June 30, 2025, NGP has the right to cause the Delaware Basin JV to sell all of the outstanding interests or assets of the Delaware Basin JV for the best available price; provided that, if NGP exercises this right, we are permitted to purchase NGP's interest at a certain call price.

(l) Intangible Assets

Intangible assets associated with customer relationships are amortized on a straight-line basis over the expected period of benefits of the customer relationships, which range from ten to twenty years. 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 4—Intangible Assets."

(m) Asset Retirement Obligations

We recognize liabilities for retirement obligations associated with our assets. 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.

(n) Leases

We account for leases under ASC 842 whereby we recognized leases on our consolidated balance sheet by recording a right-of-use asset and lease liability.

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 6—Leases."

(o) Derivatives

We use derivative instruments to hedge against changes in cash flows related to product price. We generally determine the fair value of swap contracts based on the difference between the derivative's fixed contract price and the underlying market price at the determination date. The asset or liability related to the derivative instruments is recorded on the balance sheet at the fair value of derivative assets or liabilities in accordance with ASC 815. 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 to hedge variability in interest rates and effectively lock in the benchmark interest rate at the inception of the swap. The change in fair value of interest rate swaps is recorded net as a gain or loss on designated cash flow hedges on the consolidated statements of comprehensive income. Monthly, upon settlement, we reclassify the gain or loss associated with the interest rate swap into interest expense from accumulated other comprehensive income (loss).

For additional information, see “Note 13—Derivatives.”

(p) Concentrations of Credit Risk

Financial instruments, which potentially subject us to concentrations of credit risk, consist primarily of trade accounts receivable and commodity financial instruments. Management believes the risk is limited, other than our exposure to key 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 for the years ended December 31, 2023, 2022, or 2021. No other customers represented greater than 10% of our consolidated revenues during the periods presented.

	Year Ended December 31,		
	2023	**2022**	**2021**
Dow Hydrocarbons and Resources LLC	10.4 %	14.2 %	14.5 %
Marathon Petroleum Corporation	19.3 %	14.7 %	13.4 %

We continually monitor and review the credit exposure of our counterparties 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, 2023, we had no reserve for uncollectible receivables. For the year ended December 31, 2022, we had a $0.1 million reserve for uncollectible receivables.

(q) Environmental Costs

Environmental expenditures are expensed or capitalized depending on the nature of the expenditures and the future economic benefit. Expenditures that relate to an existing condition caused by past operations that do not contribute to current or future revenue generation are expensed. Liabilities for these expenditures are recorded on an undiscounted basis (or a discounted basis when the obligation can be settled at fixed and determinable amounts) when environmental assessments or clean-ups are probable and the costs can be reasonably estimated. Environmental expenditures were not material for the years ended December 31, 2023, 2022, and 2021.

(r) 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 15—Commitments and Contingencies.”

(s) 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 $32.1 million and $34.9 million as of December 31, 2023 and 2022, respectively, are included in “Long-term debt” on the consolidated balance sheets as a direct reduction from the carrying amount of the debt.

(t) 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. At the time of the exercise, we and the interest holder did not agree on the value of the interest and a lawsuit was filed by the interest holder. As part of a settlement effected with the interest holder in January 2023, we settled the redemption of the mandatorily redeemable non-controlling interest for $10.5 million.

(3) Acquisitions and Divestitures

Amarillo Rattler Acquisition

On April 30, 2021, we completed the acquisition of Amarillo Rattler, LLC, the owner of a gathering and processing system located in the Midland Basin. In connection with the purchase, we entered into an amended and restated natural gas gathering and processing agreement with Diamondback E&P LLC, strengthening our dedicated acreage position with that entity. We acquired the system with an upfront payment of $50.0 million, which was paid with cash-on-hand, with an additional $10.0 million that was paid on April 30, 2022, and contingent consideration capped at $15.0 million and payable between 2024 and 2026 based on Diamondback E&P LLC's drilling activity above historical levels.

Under the acquisition method of accounting, the acquired assets of Amarillo Rattler, LLC have been recorded at their respective fair values as of the date of the acquisition. Determining the fair value of the assets of Amarillo Ratter, LLC requires judgment and certain assumptions to be made, particularly related to the valuation of acquired customer relationships. The inputs and assumptions related to the customer relationships are categorized as level 3 in the fair value hierarchy. The following table presents the fair value of the identified assets received and liabilities assumed at the acquisition date (in millions):

Consideration		
Cash (including working capital payment)	$	50.6
Installment payable		10.0
Contingent consideration fair value (1)		6.9
Total consideration:	$	67.5
Purchase price allocation		
Assets acquired:		
Current assets (including $1.3 million in cash)	$	1.4
Property and equipment		16.3
Intangible assets		50.6
Other assets, net (2)		0.6
Liabilities assumed:		
Current liabilities		(0.8)
Other long-term liabilities (2)		(0.6)
Net assets acquired	$	67.5

(1) The estimated fair value of the Amarillo Rattler, LLC contingent consideration was calculated in accordance with the fair value guidance contained in ASC 820. There are a number of assumptions and estimates factored into these fair values and actual contingent consideration payments could differ from the estimated fair values.
(2) "Other assets, net" and "Other long-term liabilities" consist of the right-of-use asset and lease liability, respectively, recorded through the acquisition of Amarillo Rattler, LLC.

Barnett Shale Acquisition

On July 1, 2022, we completed the Barnett Shale Acquisition for a cash purchase price of $275.0 million plus working capital of $14.5 million. These assets include approximately 400 miles of lean and rich natural gas gathering pipeline and three processing plants with 425 MMcf/d of total processing capacity. We completed this acquisition to increase the scale of our North Texas assets and realize efficiencies by redeploying redundant assets to our other segments, including the Permian segment in the near-term and the CCS business in the future.

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

Consideration		
Cash (including working capital payment)	$	289.5
Purchase price allocation		
Assets acquired:		
Current assets	$	17.3
Property and equipment		275.0
Liabilities assumed:		
Current liabilities		(2.8)
Net assets acquired	$	289.5

We incurred $0.4 million of transaction costs related to the Barnett Shale Acquisition for the year ended December 31, 2022. These costs are included in general and administrative costs in the accompanying consolidated statements of operations.

For the period from July 1, 2022 through December 31, 2022, we recognized $39.6 million of revenue and $24.1 million of net income related to the assets acquired.

Central Oklahoma Acquisition

On December 19, 2022, we completed the Central Oklahoma Acquisition for a cash purchase price of $95.8 million plus working capital of $5.1 million and an earnout valued at $1.3 million as of December 31, 2022, which was calculated in accordance with ASC 820. The earnout is payable between 2024 and 2027 based on fee revenue earned on certain contractually specified volumes for the annual periods beginning January 1, 2023 through December 31, 2026. The acquired assets include approximately 900 miles of lean and rich natural gas gathering pipeline and two processing plants with 280 MMcf/d of total processing capacity. We completed this acquisition to increase the scale and efficiency of our Central Oklahoma assets.

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

Consideration		
Cash (including working capital payment)	$	100.9
Contingent consideration		1.3
Total consideration	$	102.2
Purchase price allocation		
Assets acquired:		
Current assets	$	6.0
Property and equipment		97.1
Other assets, net (1)		0.9
Liabilities assumed:		
Current liabilities		(1.4)
Other long-term liabilities (1)		(0.4)
Net assets acquired	$	102.2

(1) "Other assets, net" and "Other long-term liabilities" consist of the right-of-use assets and lease liabilities, respectively, obtained through the Central Oklahoma Acquisition.

We incurred $0.3 million and $0.5 million of transaction costs related to the Central Oklahoma Acquisition for the years ended December 31, 2023 and December 31, 2022, respectively. These costs are included in general and administrative costs in the accompanying consolidated statements of operations.

For the period from December 19, 2022 through December 31, 2022, we recognized $1.7 million of revenue and $0.6 million of net income related to the assets acquired.

Contingent Consideration. The following table represents our change in carrying value of the Amarillo Rattler Acquisition and Central Oklahoma Acquisition contingent consideration liabilities for the periods presented (in millions):

	Year Ended December 31,		
	2023	2022	2021
Amarillo Rattler Acquisition contingent consideration			
Contingent consideration liability, beginning of period	$ 4.2	$ 6.9	$ —
Contingent consideration liability recorded upon acquisition (1)	—	—	6.9
Change in fair value	0.6	(2.7)	—
Contingent consideration liability, end of period	$ 4.8	$ 4.2	$ 6.9
Central Oklahoma Acquisition contingent consideration			
Contingent consideration liability, beginning of period	$ 1.3	$ —	$ —
Contingent consideration liability recorded upon acquisition (2)	—	1.3	—
Change in fair value	0.6	—	—
Contingent consideration liability, end of period	$ 1.9	$ 1.3	$ —
Total contingent consideration			
Contingent consideration liability, beginning of period	$ 5.5	$ 6.9	$ —
Contingent consideration liability recorded upon acquisition (1)(2)	—	1.3	6.9
Change in fair value	1.2	(2.7)	—
Contingent consideration liability, end of period	$ 6.7	$ 5.5	$ 6.9

(1) The contingent consideration for the Amarillo Rattler Acquisition was recorded on April 30, 2021.
(2) The contingent consideration for the Central Oklahoma Acquisition was recorded on December 19, 2022.

Pro Forma of Acquisitions for the Years Ended December 31, 2022 and 2021

The following unaudited pro forma condensed consolidated financial information (in millions) for the years ended December 31, 2022 and 2021 gives effect to the Barnett Shale Acquisition on July 1, 2022 and the Central Oklahoma Acquisition on December 19, 2022 as if each of the acquisitions had occurred on January 1, 2021. On a historical pro forma basis, our consolidated revenues, net income (loss), total assets, and earnings per unit amounts would not have differed materially had the Amarillo Rattler Acquisition been completed on January 1, 2021 rather than April 30, 2021.

The unaudited pro forma condensed consolidated financial information has been included for comparative purposes only and is not necessarily indicative of the results that might have occurred had the transactions taken place on the dates indicated and is not intended to be a projection of future results.

	Year Ended December 31,	
	2022	2021
Pro forma total revenues	$ 9,630.4	$ 6,782.9
Pro forma net income	$ 534.3	$ 157.5

ORV Divestitures

On November 1, 2023, we sold certain ORV crude assets in our Louisiana segment to a subsidiary of Ergon, Inc. in exchange for cash consideration of approximately $59.2 million, subject to post-closing purchase price adjustments, and a contingent payment of an additional $0.5 million subject to the buyer's pursuit of certain commercial opportunities within three years after the acquisition date.

On November 3, 2023, we sold our remaining ORV assets in our Louisiana segment to Blue Racer Midstream, LLC in exchange for cash consideration of approximately $9.8 million, subject to post-closing purchase price adjustments.

(4) 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 ranged from 10 to 20 years at the time the intangible assets were originally recorded. The weighted average amortization period for intangible assets is 14.9 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, 2023			
Customer relationships, beginning of period	$ 1,844.8	$ (923.6)	$ 921.2
Amortization expense	—	(127.6)	(127.6)
Customer relationships, end of period	$ 1,844.8	$ (1,051.2)	$ 793.6
Year Ended December 31, 2022			
Customer relationships, beginning of period	$ 1,844.8	$ (795.1)	$ 1,049.7
Amortization expense	—	(128.5)	(128.5)
Customer relationships, end of period	$ 1,844.8	$ (923.6)	$ 921.2
Year Ended December 31, 2021			
Customer relationships, beginning of period	$ 1,794.2	$ (668.8)	$ 1,125.4
Customer relationships obtained from acquisition of business	50.6	—	50.6
Amortization expense	—	(126.3)	(126.3)
Customer relationships, end of period	$ 1,844.8	$ (795.1)	$ 1,049.7

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

2024	$ 127.6
2025	110.2
2026	106.3
2027	106.3
2028	106.3
Thereafter	236.9
Total	$ 793.6

(5) Related Party Transactions

(a) Transactions with the Cedar Cove JV

We process natural gas and purchase the related residue gas and NGLs from the Cedar Cove JV.We recorded the following amounts (in millions) on our consolidated balance sheets related to our transactions with the Cedar Cove JV:

	December 31, 2023	December 31, 2022
Accrued natural gas, NGLs, condensate, and crude oil purchases	$ 0.3	$ 2.5

We recorded the following amounts (in millions) on our consolidated statements of operations related to our transactions with the Cedar Cove JV:

	Year Ended December 31,		
	2023	2022	2021
Midstream services revenue	$ 2.5	$ 2.2	$ —
Cost of sales	(7.5)	(28.2)	(17.9)

(b) Transactions with GIP

In March 2022, our data center provider since 2009, CyrusOne Inc. ("CyrusOne"), was purchased by an entity that is owned collectively by funds affiliated with GIP and Kohlberg Kravis Roberts & Co. L.P. We paid CyrusOne $0.2 million in fees for data center services for each of the years ended December 31, 2023 and 2022.

GIP Repurchase Agreement

On February 15, 2022, we entered into an agreement with GIP pursuant to which we agreed to repurchase, on a quarterly basis, a pro rata portion of the ENLC common units held by GIP, based upon the number of common units purchased by us during the applicable quarter from public unitholders under our common unit repurchase program. The number of ENLC common units held by GIP that we repurchase in any quarter is calculated such that GIP's then-existing economic ownership percentage of our outstanding common units is maintained after our repurchases of common units from public unitholders are taken into account, and the per unit price we pay to GIP is the average per unit price paid by us for the common units repurchased from public unitholders, less broker commissions, which are not paid with respect to the GIP units. The repurchase agreement terminated as of December 31, 2022 in accordance with its terms.

On December 20, 2022, we entered into a renewed repurchase agreement with GIP for 2023 (the "Second Repurchase Agreement") on terms substantially similar to those of the repurchase agreement entered into by the Company and GIP on February 15, 2022. The Second Repurchase Agreement terminated on December 31, 2023. On January 16, 2024, we entered into a new repurchase agreement with GIP with terms substantially similar to the Second Repurchase Agreement. The current repurchase agreement will renew for successive one-year terms (each, a "Renewal Year") on January 1 of each Renewal Year, with the first Renewal Year beginning on January 1, 2025, unless either the Company or the GIP Entities elects to terminate the Repurchase Agreement prior to the start of any Renewal Year, during a two-week period in December preceding the applicable Renewal Year. See "Note 10—Members' Equity" for additional information on the activity related to the GIP repurchase agreement.

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

(6) 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 represented $40.4 million of our lease liability and $20.7 million of our right-of-use asset as of December 31, 2023. Our office leases represented $46.2 million of our lease liability and $24.2 million of our right-of-use asset as of December 31, 2022. 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 month to month until canceled by us or the lessor. Compression and other field equipment rentals represented $41.7 million of our lease liability and $42.5 million of our right-of-use asset as of December 31, 2023. Compression and other field equipment rentals represented $30.6 million of our lease liability and $33.0 million of our right-of-use asset as of December 31, 2022. 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 represented $15.7 million of our lease liability and $12.4 million of our right-of-use asset as of December 31, 2023. Land and land easement leases represented $15.6 million of our lease liability and $12.3 million of our right-of-use asset as of December 31, 2022.

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

Operating leases:	December 31, 2023	December 31, 2022
Other assets, net	$ 75.6	$ 69.5
Other current liabilities	$ 28.2	$ 26.2
Other long-term liabilities	$ 69.6	$ 66.2
Other lease information		
Weighted-average remaining lease term—Operating leases	7.7 years	8.7 years
Weighted-average discount rate—Operating leases	5.3 %	4.7 %

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. Sublease income is recognized as a reduction in “General and administrative,” “Operating expenses,” or as “Other income” depending on the nature of the subleased asset. The components of total lease expense are as follows (in millions):

	Year Ended December 31,		
	2023	2022	2021
Operating lease expense:			
Long-term operating lease expense	$ 34.6	$ 28.2	$ 21.7
Short-term lease expense	41.3	34.3	17.5
Variable lease expense	18.6	18.8	15.6
Impairments	—	—	0.2
Total lease expense, before sublease income	94.5	81.3	55.0
Sublease income	(1.8)	(1.1)	—
Total lease expense, net of sublease income	$ 92.7	$ 80.2	$ 55.0

Lease Maturities

The following table summarizes the maturity of our lease liability as of December 31, 2023 (in millions):

	Total	2024	2025	2026	2027	2028	Thereafter
Undiscounted operating lease liability	$ 123.8	$ 31.8	$ 24.4	$ 15.2	$ 9.1	$ 8.7	$ 34.6
Reduction due to present value	(26.0)	(4.3)	(3.2)	(2.3)	(1.8)	(1.4)	(13.0)
Operating lease liability	$ 97.8	$ 27.5	$ 21.2	$ 12.9	$ 7.3	$ 7.3	$ 21.6

(7) Long-Term Debt

As of December 31, 2023 and 2022, long-term debt consisted of the following (in millions):

	December 31, 2023			December 31, 2022		
	Outstanding Principal	Premium (Discount)	Long-Term Debt	Outstanding Principal	Premium (Discount)	Long-Term Debt
AR Facility due 2025 (1)	300.0	—	300.0	500.0	—	500.0
Revolving Credit Facility due 2027 (2)	—	—	—	255.0	—	255.0
ENLK's 4.40% Senior unsecured notes due 2024	97.9	—	97.9	97.9	—	97.9
ENLK's 4.15% Senior unsecured notes due 2025	421.6	—	421.6	421.6	(0.1)	421.5
ENLK's 4.85% Senior unsecured notes due 2026	491.0	(0.2)	490.8	491.0	(0.2)	490.8
ENLC's 5.625% Senior unsecured notes due 2028	500.0	—	500.0	500.0	—	500.0
ENLC's 5.375% Senior unsecured notes due 2029	498.7	—	498.7	498.7	—	498.7
ENLC's 6.50% Senior unsecured notes due 2030	1,000.0	(2.7)	997.3	700.0	—	700.0
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	(5.0)	445.0	450.0	(5.2)	444.8
ENLK's 5.45% Senior unsecured notes due 2047	500.0	(0.1)	499.9	500.0	(0.1)	499.9
Debt classified as long-term, including current maturities of long-term debt	$ 4,609.2	$ (8.2)	4,601.0	$ 4,764.2	$ (5.8)	4,758.4
Debt issuance cost (3)			(32.1)			(34.9)
Less: Current maturities of long-term debt (4)			(97.9)			—
Long-term debt, net of unamortized issuance cost			$ 4,471.0			$ 4,723.5

(1) The effective interest rate was 6.4% and 5.3% at December 31, 2023 and 2022, respectively.
(2) The effective interest rate was 6.5% at December 31, 2022.
(3) Net of accumulated amortization of $20.0 million and $15.1 million at December 31, 2023 and 2022, respectively.
(4) The outstanding balance, net of debt issuance costs, of ENLK's 4.40% senior unsecured notes as of December 31, 2023 are classified as "Current maturities of long-term debt" on the consolidated balance sheet as these notes mature on April 1, 2024.

Maturities

Maturities for the long-term debt as of December 31, 2023 are as follows (in millions):

2024	$ 97.9
2025	721.6
2026	491.0
2027	—
2028	500.0
Thereafter	2,798.7
Subtotal	4,609.2
Less: net discount	(8.2)
Less: debt issuance cost	(32.1)
Less: current maturities of long-term debt	(97.9)
Long-term debt, net of unamortized issuance cost	$ 4,471.0

Revolving Credit Facility

On June 3, 2022, we amended and restated our prior revolving credit facility by entering into the Revolving Credit Facility. As a result, we recognized a $0.5 million loss on extinguishment of debt. The Revolving Credit Facility amended our prior revolving credit facility by, among other things, (i) decreasing the lenders' commitments from $1.75 billion to $1.40 billion, (ii) modifying the leverage ratio financial covenant calculation to net from the funded indebtedness numerator the lesser of (a) consolidated unrestricted cash of ENLC and (b) $50.0 million, (iii) removing the consolidated interest coverage ratio financial covenant, (iv) extending the maturity date from January 25, 2024 to June 3, 2027, (v) replacing the ability of ENLC to elect that borrowings accrue interest at LIBOR, plus a margin, with the ability of ENLC to elect that borrowings accrue interest at a forward-looking term rate based on SOFR ("Term SOFR"), plus a margin and a Term SOFR spread adjustment, (vi) increasing the size of a permitted receivables financing to $500.0 million from $350.0 million, and (vii) permitting, but not requiring, the establishment by ENLC (subject to approval by Bank of America, N.A., as administrative agent, and lenders holding a majority of the revolving commitments) of specified key performance indicators with respect to environmental, social, and/or governance targets that may result in a pricing increase or decrease under the Revolving Credit Facility of up to 0.05% per annum for the margin on borrowings and letters of credit and 0.02% per annum for the commitment fees.

The Revolving Credit Facility will mature on June 3, 2027, unless ENLC requests, and the requisite lenders agree, to extend it pursuant to its terms. The Revolving Credit Facility contains certain financial, operational, and legal covenants. The financial covenant is tested on a quarterly basis, based on the rolling four-quarter period that ends on the last day of each fiscal quarter. The financial covenant requires ENLC to maintain a ratio of consolidated net indebtedness to consolidated EBITDA of no more than 5.0 to 1.0.

Under the terms of the Revolving Credit Facility, if we consummate an acquisition in which the aggregate purchase price is $50.0 million or more, we can elect to increase the maximum allowed ratio of consolidated net 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 Revolving Credit Facility bear interest at ENLC's option at Term SOFR plus a Term SOFR spread adjustment of 0.10% per annum ("Adjusted Term SOFR") and an applicable margin (ranging from 1.125% to 2.00%) or the Base Rate (the highest of the federal funds rate plus 0.50%, one-month Adjusted Term SOFR 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 Revolving Credit Facility, or a change in control (as defined in the Revolving Credit Facility) amounts outstanding under the Revolving Credit Facility, if any, may become due and payable immediately.

ENLK is a guarantor under the Revolving Credit Facility. In the event that ENLC's obligations under the Revolving Credit Facility are accelerated due to a default, ENLK will be liable for the entire outstanding balance and 105% of the outstanding letters of credit under the Revolving Credit Facility. There were no outstanding borrowings under the Revolving Credit Facility and $26.7 million in outstanding letters of credit as of December 31, 2023.

At December 31, 2023, we were in compliance with and expect to be in compliance with the financial covenants of the Revolving Credit Facility for at least the next twelve months.

AR Facility

On October 21, 2020, the SPV entered into the AR Facility. In connection with the AR Facility, certain subsidiaries of ENLC 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.

In 2021 and 2022, the SPV entered into several amendments to the AR Facility to, among other things: (i) increase the commitments thereunder to $500.0 million (ii) extend the scheduled termination date to August 1, 2025, unless extended or earlier terminated in accordance with its terms, and (iii) reduce the effective draw down fee to 0.90%.

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 primarily of billed and unbilled accounts receivable of $629.3 million as of December 31, 2023. As of December 31, 2023, the AR Facility had a borrowing base of $404.2 million and there were $300.0 million in outstanding borrowings under the AR Facility.

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 at the applicable SOFR plus a credit spread adjustment of 0.10%, plus a drawn fee in the amount of 0.90% at December 31, 2023. 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 August 1, 2025, unless extended or earlier terminated in accordance with its terms, 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 Revolving Credit Facility or certain other indebtedness, certain events negatively affecting the overall credit quality of the receivables held as collateral occur, a change in control occurs, or if the net consolidated leverage ratio of ENLC exceeds limits identical to those in the Revolving Credit Facility.

At December 31, 2023, 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.

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
2030 Notes	September 1, 2030	Prior to March 1, 2030	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 indentures governing the 2028 Notes and the 2030 Notes provide that if a Change of Control Triggering Event (as defined in the indenture) occurs, ENLC must offer to repurchase the 2028 Notes and the 2030 Notes at a price equal to 101% of the principal amount of such 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, 2023, 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. All interest payments for senior unsecured notes are due semi-annually, in arrears.

Issuances and Repurchases of Senior Unsecured Notes

On April 3, 2023, we completed the sale of an additional $300.0 million aggregate principal amount of ENLC's 6.50% senior unsecured notes due 2030 (the "Additional Notes") at a price to the public of 99% of their face value. The Additional Notes were offered as an additional issuance of our existing 6.50% senior unsecured notes due 2030 that we issued on August 31, 2022 in an aggregate principal amount of $700.0 million. Net proceeds of approximately $294.5 million were used to repay a portion of the borrowings under the Revolving Credit Facility. The Additional Notes are fully and unconditionally guaranteed by ENLK.

On August 31, 2022, ENLC completed the sale of $700.0 million in aggregate principal amount of ENLC's 6.50% senior unsecured notes due September 1, 2030 (the "2030 Notes") at 100% of their face value. Interest on the 2030 Notes will be payable on March 1 and September 1 of each year beginning on March 1, 2023, until their maturity on September 1, 2030. The 2030 Notes are fully and unconditionally guaranteed by ENLK. We used the net proceeds of approximately $693.0 million and available cash to settle ENLK's debt tender offer to repurchase $700.0 million in aggregate principal amount of its senior unsecured notes. The repurchased notes consisted of $404.4 million of outstanding aggregate principal amount of ENLK's 4.40% senior unsecured notes due 2024 (the "2024 Notes") and $295.6 million of outstanding aggregate principal amount of ENLK's 4.15% senior unsecured notes due 2025 (the "2025 Notes"). Total consideration for the repurchased 2024 Notes and the 2025 Notes was $705.3 million, including $21.0 million of debt tender premium and $15.7 million of discount.

Activity related to the repurchases of ENLK's senior unsecured notes from the settled debt tender offer consisted of the following (in millions):

	Year Ended December 31, 2022
Debt repurchased	$ 700.0
Aggregate payments	(705.3)
Net discount on repurchased debt	(1.0)
Loss on extinguishment of debt	$ (6.3)

Additionally, for the year ended December 31, 2022, and prior to the tender offer, we repurchased a portion of the outstanding 2024 Notes and 2025 Notes in open market transactions. Activity related to the repurchases of our senior unsecured notes in open market transactions consisted of the following (in millions):

	Year Ended December 31, 2022
Debt repurchased	$ 23.1
Aggregate payments	(22.5)
Gain on extinguishment of debt	$ 0.6

(8) Income Taxes

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

	Year Ended December 31,		
	2023	2022	2021
Current income tax expense	$ (0.7)	$ (0.4)	$ (0.8)
Deferred income tax benefit (expense)	(62.1)	95.3	(24.6)
Income tax benefit (expense)	$ (62.8)	$ 94.9	$ (25.4)

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

	Year Ended December 31,		
	2023	2022	2021
Expected income tax expense based on federal statutory tax rate	$ (56.5)	$ (55.9)	$ (10.0)
State income tax expense, net of federal benefit	(7.2)	(7.0)	(1.4)
Unit-based compensation (1)	7.7	0.7	(3.1)
Statutory rate changes (2)	—	—	(10.2)
Change in valuation allowance	(1.2)	151.6	1.7
Other	(5.6)	5.5	(2.4)
Total income tax benefit (expense)	$ (62.8)	$ 94.9	$ (25.4)

(1) Related to book-to-tax differences recorded upon the vesting of unit-based awards.
(2) Effective January 1, 2022, Oklahoma House Bill 2960 resulted in a change in the corporate income tax rate from 6% to 4% and Louisiana Senate Bill No. 159 resulted in a change in the corporate income tax rate from 8% to 7.5%. Accordingly, we recorded deferred tax expense related to our Oklahoma and Louisiana operations in the amount of $7.6 million and $2.6 million, respectively, for the year ended December 31, 2021 due to a remeasurement of deferred tax assets.

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 sheets. Our deferred income tax assets and liabilities as of December 31, 2023 and 2022 are as follows (in millions):

	December 31, 2023	December 31, 2022
Deferred income tax assets:		
Federal net operating loss carryforward	$ 627.2	$ 636.5
State net operating loss carryforward	77.2	77.6
Interest deduction limitation (1)	53.0	57.6
Other	2.1	2.4
Total deferred tax assets, gross	759.5	774.1
Valuation allowance	(1.2)	—
Total deferred tax assets, net of valuation allowance	758.3	774.1
Deferred tax liabilities:		
Property, plant, equipment, and intangible assets (2)	(862.5)	(816.8)
Total deferred tax liabilities	(862.5)	(816.8)
Deferred tax liability, net	$ (104.2)	$ (42.7)

(1) Related to book-to-tax differences between the allowable interest deduction amount under Section 163j of the Internal Revenue Code of 1986, as amended.
(2) Includes our investment in ENLK and primarily relates to differences between the book and tax bases of property and equipment.

As of December 31, 2023, we had federal net operating loss ("NOL") carryforwards of $3.0 billion that represented a net deferred tax asset of $627.2 million. As of December 31, 2023, we had state NOL carryforwards of $1.6 billion that represented a net deferred tax asset of $77.2 million. A portion of these carryforwards will begin expiring in 2027 through 2043. Federal NOLs incurred in 2018 and in future years (approximately $2.8 billion of our federal NOL carryforwards) may be carried forward indefinitely, but the deductibility of such federal NOLs is limited, while federal NOLs incurred prior to 2018 (approximately $0.2 billion of our NOL carryforwards) may be carried forward for only twenty years, but the deductibility of such NOL carryforwards generally is not limited unless we were to undergo an IRC Section 382 "ownership change."

We provide a valuation allowance, if necessary, to reduce deferred tax assets, if all, or some portion, of such assets will more than likely not be realized. We continually review the realizability of our deferred tax assets, including an analysis of factors such as future taxable income, reversal of existing taxable temporary differences, and tax planning strategies. We assessed whether a valuation allowance should be recorded against our deferred tax assets based on consideration of all available evidence, using a "more likely than not" standard. In assessing the need for a valuation allowance, we considered both positive and negative evidence related to the likelihood of realization of deferred tax assets. In making such assessment, more weight was given to evidence that could be objectively verified, including recent cumulative losses. Future sources of taxable income were also considered in determining the amount of the recorded valuation allowance.

For the year ended December 31, 2021, we recorded a $1.7 million net reduction in the valuation allowance as a result of the remeasurement of the state deferred tax assets and liabilities from the statutory rate changes. For the year ended December 31, 2022, we further reduced the valuation allowance by $151.6 million as a result of improved current and expected future operating income. For the year ended December 31, 2023, we established a valuation allowance of $1.2 million, primarily related to state tax operating loss carryforwards for which we did not believe a tax benefit was more likely than not to be realized. As of December 31, 2023, management believes it is more likely than not that the Company will realize the benefits of the deferred tax assets, net of valuation allowance.

For the years ended December 31, 2023 and 2022, 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, 2023, tax years 2019 through 2023 remain subject to examination by various taxing authorities.

Excise Tax on Common Unit Repurchases

The Inflation Reduction Act of 2022, which was enacted on August 16, 2022, includes a new tax provision that imposes a 1% excise tax on common unit repurchases, net of common unit issuances, made after December 31, 2022. As a result, we accrued $2.0 million of excise tax in connection with our net common unit repurchases for the year ended December 31, 2023, which was recorded as an adjustment to the cost basis of common units repurchased in “Members’ equity” and “Other current liabilities” on the consolidated balance sheet as of December 31, 2023.

(9) Certain Provisions of the ENLK Partnership Agreement

(a) Series B Preferred Units

As of December 31, 2023 and 2022, there were 54,575,638 and 54,168,359 Series B Preferred Units issued and outstanding, respectively.

Issuance

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”). On August 4, 2021, Enfield Holdings, L.P. (“Enfield”) sold all of its Series B Preferred Units and ENLC Class C Common Units representing limited liability company interests in ENLC to Brookfield Infrastructure Partners L.P. and funds managed by Oaktree Capital Management, L.P.

Redemptions

In January 2022 and December 2021, we redeemed 3,333,334 and 3,300,330 Series B Preferred Units for total consideration of $50.5 million and $50.0 million plus accrued distributions, respectively. In addition, upon each such redemption, a corresponding number of ENLC Class C Common Units were automatically cancelled. The redemption price in each redemption represented 101% of the preferred units’ par value. In connection with the Series B Preferred Unit redemption, we agreed with the holders of the Series B Preferred Units to pay cash in lieu of making a quarterly distribution in-kind of additional Series B Preferred Units (the “PIK Distribution”) through the distribution declared for the fourth quarter of 2022.

Conversion and Distributions

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 the option of the holder of the Series B Preferred Units at any time, or in whole at our option, provided the daily volume-weighted average closing price of the ENLC common units 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.

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 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) $0.28125 per Series B Preferred Unit (the “Cash Distribution Component”), divided by (y) the Issue Price. Except as described above with respect to distributions made until the distribution declared for the fourth quarter of 2022, the quarterly cash distribution (the “Series B 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 PIK Distribution and (ii) the Series B Preferred Units that would have been distributed in the PIK Distribution if such calculation applied the Series B Exchange Ratio instead of the one-to-one ratio (subject to certain adjustments).

On September 8, 2023, in connection with ENLK’s qualification of the Series B Preferred Units to be eligible to be deposited through the Depository Trust Company, we amended and restated the limited partnership agreement of ENLK to, among other things, (i) reflect the cancellation of all outstanding ENLC Class C Common Units, which were non-economic equity interests previously held by the holders of the Series B Preferred Units and permitted such holders to participate in any vote of the holders of ENLC common units, (ii) provide for the termination of any rights of the holders of the Series B Preferred

Units to PIK Distributions with respect to, and following, the earlier to occur of (x) any quarter in which the holders of the Series B Preferred Units give notice to the General Partner of its election to terminate such PIK Distribution right and (y) the quarter ending June 30, 2024, and (iii) in connection with such termination of PIK Distributions, increase the cash distribution per Series B Preferred Unit from $0.28125 to $0.31875, in addition to the continued payment of the Series B Excess Cash Payment Amount (as defined in ENLK's limited partnership agreement).

Income is allocated to the Series B Preferred Units in an amount equal to the quarterly distribution with respect to the period earnedA summary of the distribution activity relating to the Series B Preferred Units during the years ended December 31, 2023, 2022, and 2021 is provided below:

Declaration period	PIK Distribution	Cash distribution (in millions)		Date paid
2023				
First Quarter of 2023	135,421	$	15.2	May 12, 2023
Second Quarter of 2023	135,759	$	15.3	August 11, 2023
Third Quarter of 2023	136,099	$	15.3	November 10, 2023
Fourth Quarter of 2023	136,439	$	15.3	February 9, 2024
2022				
First Quarter of 2022	—	$	17.5	May 13, 2022 (2)
Second Quarter of 2022	—	$	17.3	August 12, 2022
Third Quarter of 2022	—	$	17.3	November 14, 2022
Fourth Quarter of 2022	—	$	17.3	February 13, 2023
2021				
First Quarter of 2021	150,871	$	17.0	May 14, 2021
Second Quarter of 2021	151,248	$	17.0	August 13, 2021
Third Quarter of 2021	151,626	$	17.1	November 12, 2021
Fourth Quarter of 2021	—	$	19.2	February 11, 2022 (1)

(1) In December 2021 and January 2022, we paid $0.9 million and $1.0 million, respectively, of accrued distributions related to the fourth quarter of 2021 on redeemed Series B Preferred Units. The remaining distribution of $17.3 million related to the fourth quarter of 2021 was paid on February 11, 2022.
(2) In January 2022, we paid $0.3 million of accrued distributions related to the first quarter of 2022 on redeemed Series B Preferred Units. The remaining distribution of $ 17.2 million related to the first quarter of 2022 was paid on May 13, 2022.

Allocation of Taxable Income to the Series B Preferred Units

For tax purposes, holders of Series B Preferred Units are allocated items of gross income from ENLK in respect of each Series B Preferred Unit until the cumulative amount of gross income so allocated equals the cumulative amount of distributions made in respect of such Series B Preferred Unit, but not in excess of the positive net income of ENLK for the allocation year (the "Allocation Cap"). As of December 31, 2023, due to the application of the Allocation Cap, the cumulative amount of distributions made in respect of each Series B Preferred Unit exceeded the cumulative amount of gross income allocated to each Series B Preferred Unit by $6.79 per Series B Preferred Unit (the "Catch-Up Income Allocation"). As a result, holders of Series B Preferred Units will ultimately be allocated taxable income during future periods equal to the Catch-Up Income Allocation plus the amount of distributions received in respect of Series B Preferred Units, if ENLK generates positive net income.

(b) Series C Preferred Units

As of December 31, 2023 and 2022, there were 366,500 and 381,000 Series C Preferred Units issued and outstanding, respectively.

Issuance

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.

Repurchases

A summary of the repurchase activity relating to the Series C Preferred Units is provided below:

Transaction date	Series C Preferred Units Repurchased	Total Consideration (in millions)	Percent Represented of Repurchased Preferred Units' Par Value
2023			
February 2023	4,500	$ 3.9	87 %
November 2023	3,000	$ 2.7	90 %
December 2023	7,000	$ 6.5	93 %
2022			
October 2022	19,000	$ 15.2	80 %

Distributions

Income is allocated to the Series C Preferred Units in an amount equal to the earned distribution for the respective reporting period. A summary of the distribution activity relating to the Series C Preferred Units is provided below:

Declaration period (1)	Distribution rate (2)	Cash distribution (in millions)	Date paid/payable
2024			
December 15, 2023 - March 14, 2024	9.749 %	$ 9.0	March 15, 2024
2023			
December 15, 2022 – March 14, 2023	8.846 %	$ 8.4	March 15, 2023
March 15, 2023 – June 14, 2023	9.051 %	$ 8.7	June 15, 2023
June 15, 2023 – September 14, 2023	9.618 %	$ 9.3	September 15, 2023
September 15, 2023 - December 14, 2023	9.782 %	$ 9.3	December 15, 2023
2022			
December 15, 2021 – June 14, 2022	6.000 %	$ 12.0	June 15, 2022
June 15, 2022 – December 14, 2022	6.000 %	$ 11.4	December 15, 2022
2021			
December 15, 2020 – June 14, 2021	6.000 %	$ 12.0	June 15, 2021
June 15, 2021 – December 14, 2021	6.000 %	$ 12.0	December 15, 2021

(1) Distributions on the Series C Preferred Units accrued and were 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, accrue 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.

(2) The initial distribution rate for the Series C Preferred Units from the date of original issue through December 14, 2022 was 6.0% per year. Starting on December 15, 2022, distributions on the Series C Preferred Units accumulate for each distribution period at a percentage of the $1,000 liquidation preference per unit equal to the floating rate of the three-month LIBOR plus a spread of 4.11%. Starting on September 15, 2023, distributions on the Series C Preferred Units are based on the forward-looking term rate based on SOFR ("Term SOFR"), plus a Term SOFR spread adjustment of 0.26161%, plus a spread of 4.11%.

(10) Members' Equity

(a) Common Unit Repurchase Program

In November 2020, the Board authorized a common unit repurchase program, subsequently reauthorizing the program during the years ended December 31, 2023, 2022, and 2021. The table below provides a summary of the Board's authorizations of the common unit repurchase program.

Date	Board Action	Authorized Amount (in millions)(1)
November 2020	Authorization of common unit repurchase program	$ 100
April 2021	Reauthorization of common unit repurchase program	$ 100
January 2022	Reauthorization of common unit repurchase program and set amount available for repurchases for 2022	$ 100
July 2022	Increase in 2022 common unit repurchase program	$ 100
December 2022	Reauthorization of common unit repurchase program and set amount available for repurchases for 2023	$ 200
November 2023	Increase in 2023 common unit repurchase program	$ 50
December 2023	Reauthorization of common unit repurchase program and set amount available for repurchases for 2024	$ 200

(1) Starting on February 15, 2022, the authorized amount includes repurchases of common units held by GIP. Refer to "Note 5—Related Party Transactions" for more information on our ENLC common unit repurchase agreement with GIP.

Repurchases under the common unit repurchase program 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 Exchange Act. The repurchases will depend on market conditions and may be discontinued at any time.

The following table summarizes our ENLC common unit repurchase activity for the periods presented (in millions, except for unit amounts):

	Year Ended December 31, 2023	2022	2021
Publicly held ENLC common units	11,530,962	11,630,351	6,091,001
ENLC common units held by GIP (1)	8,846,445	6,743,703	—
Total ENLC common units	20,377,407	18,374,054	6,091,001
Aggregate cost for publicly held ENLC common units	$ 134.5	$ 111.5	$ 40.1
Aggregate cost for ENLC common units held by GIP	98.3	63.5	—
Excise tax on common unit repurchases	$ 2.0	$ —	$ —
Total aggregate cost for ENLC common units	$ 234.8	$ 175.0	$ 40.1
Average price paid per publicly held ENLC common unit (2)	$ 11.67	$ 9.59	$ 6.59
Average price paid per ENLC common unit held by GIP (2)(3)	$ 11.11	$ 9.42	$ —

(1) The units repurchased in each quarter represent GIP's pro rata share of the aggregate number of common units repurchased by us under our common unit repurchase program during the prior quarter.
(2) The average price paid per common unit excludes excise tax on common unit repurchases.
(3) The per unit price we paid to GIP in each quarter was the average per unit price paid by us for publicly held ENLC common units repurchased in the prior quarter, less broker commissions.

Additionally, on February 19, 2024, we repurchased 3,280,637 ENLC common units held by GIP at an aggregate cost of $41.5 million, or an average of $12.66 per common unit. These units represented GIP's pro rata share of the aggregate number of common units repurchased by us during the three months ended December 31, 2023. The per unit price we paid to GIP was the same as the average per unit price paid by us for publicly held ENLC common units repurchased during the same period, less broker commissions, which were not paid with respect to the GIP units. As of December 31, 2023, $41.5 million is classified as “Other current liabilities” on the consolidated balance sheets related to our obligation to repurchase our common units from GIP. See “Note 5—Related Party Transactions” for additional information relating to the GIP repurchase agreement.

(b) 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,		
	2023	2022	2021
Distributed earnings allocated to:			
Common units (1)	$ 234.3	$ 221.3	$ 192.5
Unvested unit-based awards (1)	3.9	5.2	4.5
Total distributed earnings	$ 238.2	$ 226.5	$ 197.0
Undistributed income (loss) allocated to:			
Common units	$ (31.5)	$ 131.7	$ (170.6)
Unvested unit-based awards	(0.5)	3.1	(4.0)
Total undistributed income (loss)	$ (32.0)	$ 134.8	$ (174.6)
Net income attributable to ENLC allocated to:			
Common units	$ 202.8	$ 353.0	$ 21.9
Unvested unit-based awards	3.4	8.3	0.5
Total net income attributable to ENLC	$ 206.2	$ 361.3	$ 22.4
Net income attributable to ENLC per unit:			
Basic	$ 0.45	$ 0.76	$ 0.05
Diluted	$ 0.44	$ 0.74	$ 0.05

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

The following are the unit amounts used to compute the basic and diluted earnings per unit for the periods presented (in millions):

	Year Ended December 31,		
	2023	2022	2021
Basic weighted average units outstanding:			
Weighted average common units outstanding	461.7	478.5	488.8
Diluted weighted average units outstanding:			
Weighted average basic common units outstanding	461.7	478.5	488.8
Dilutive effect of unvested restricted units	4.3	6.8	5.5
Total weighted average diluted common units outstanding	466.0	485.3	494.3

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.

(c) Distributions

A summary of our distribution activity related to the ENLC common units for the years ended December 31, 2023, 2022, and 2021, respectively, is provided below:

Declaration period	Distribution/unit	Date paid/payable
2023		
First Quarter of 2023	$ 0.12500	May 12, 2023
Second Quarter of 2023	$ 0.12500	August 11, 2023
Third Quarter of 2023	$ 0.12500	November 10, 2023
Fourth Quarter of 2023	$ 0.13250	February 9, 2024
2022		
First Quarter of 2022	$ 0.11250	May 13, 2022
Second Quarter of 2022	$ 0.11250	August 12, 2022
Third Quarter of 2022	$ 0.11250	November 14, 2022
Fourth Quarter of 2022	$ 0.12500	February 13, 2023
2021		
First Quarter of 2021	$ 0.09375	May 14, 2021
Second Quarter of 2021	$ 0.09375	August 13, 2021
Third Quarter of 2021	$ 0.09375	November 12, 2021
Fourth Quarter of 2021	$ 0.11250	February 11, 2022

(11) Investment in Unconsolidated Affiliates

As of December 31, 2023, our unconsolidated investments consisted of a38.75% ownership in GCF, a 30% ownership in the Cedar Cove JV, and a 15% ownership in the Matterhorn JV. The following table shows the activity related to our investment in unconsolidated affiliates for the periods indicated (in millions):

	Year Ended December 31,		
	2023	2022	2021
GCF			
Contributions	$ 24.6	$ 1.5	$ —
Distributions	$ (2.0)	$ —	$ (3.5)
Equity in loss	$ (4.4)	$ (3.2)	$ (9.1)
Cedar Cove JV			
Distributions	$ (0.5)	$ (0.7)	$ (0.4)
Equity in loss	$ (2.4)	$ (1.9)	$ (2.4)
Matterhorn JV			
Contributions	$ 43.5	$ 64.4	$ —
Equity in loss	$ (1.4)	$ (0.5)	$ —
Total			
Contributions	$ 68.1	$ 65.9	$ —
Distributions	$ (2.5)	$ (0.7)	$ (3.9)
Equity in loss	$ (8.2)	$ (5.6)	$ (11.5)

The following table shows the balances related to our investment in unconsolidated affiliates as of December 31, 2023 and 2022 (in millions):

	December 31, 2023	December 31, 2022
GCF	$ 44.5	$ 26.3
Cedar Cove JV (1)	(7.3)	(4.4)
Matterhorn JV	106.0	63.9
Total investment in unconsolidated affiliates	$ 143.2	$ 85.8

(1) As of December 31, 2023 and 2022, our investment in the Cedar Cove JV is classified as “Other long-term liabilities” on the consolidated balance sheets.

(12) Employee Incentive Plans

(a) Long-Term Incentive Plans

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.

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

	Year Ended December 31,		
	2023	2022	2021
Cost of unit-based compensation charged to operating expense	$ 3.7	$ 5.7	$ 6.6
Cost of unit-based compensation charged to general and administrative expense	15.5	24.7	18.7
Total unit-based compensation expense	$ 19.2	$ 30.4	$ 25.3
Amount of related income tax benefit recognized in net income (1)	$ 4.5	$ 7.1	$ 5.9

(1) The amount of related income tax benefit recognized in net income excluded book-to-tax differences recorded upon the vesting of unit-based awards. For additional information, see "Note 8—Income Taxes."

(b) Restricted Incentive Units

The restricted incentive units were 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, 2023 is provided below:

	Year Ended December 31, 2023	
Restricted Incentive Units:	**Number of Units**	**Weighted Average Grant-Date Fair Value**
Unvested, beginning of period	6,775,186	$ 5.89
Granted (1)	1,587,965	11.03
Vested (1)(2)	(2,489,603)	5.96
Forfeited	(427,568)	6.98
Unvested, end of period	5,445,980	$ 7.27
Aggregate intrinsic value, end of period (in millions)	$ 66.2	

(1) Restricted incentive units typically vest at the end of three years.
(2) Vested units included 756,556 ENLC common 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, 2023, 2022, and 2021 is provided below (in millions):

	Year Ended December 31,		
Restricted Incentive Units:	**2023**	**2022**	**2021**
Aggregate intrinsic value of units vested	$ 30.5	$ 24.4	$ 5.6
Fair value of units vested	$ 14.8	$ 19.0	$ 16.3

As of December 31, 2023, there were $16.7 million of unrecognized compensation costs that related to unvested restricted incentive units. These costs are expected to be recognized over a weighted average period of 1.8 years.

For restricted incentive unit awards granted 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 in control (if any). The Subject Grants will vest in full if death or a qualifying disability occurs prior to the Regular Vesting Date.

(c) Performance Units

We grant performance awards under the 2014 Plan. The performance award agreements provide that the vesting of performance units (i.e., performance-based restricted incentive units) granted thereunder is dependent on the achievement of certain performance goals over the applicable performance period. At the end of the vesting period, recipients receive distribution equivalents, if any, with respect to the number of performance units vested. The vesting of such units ranges from zero to 200% of the units granted depending on the extent to which the related performance goals are achieved over the relevant performance period.

Performance Unit Awards Vesting

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, which in previous years has been based on distributable cash flow ("DCF") or free cash flow after distributions ("FCFAD") (as applicable "Cash Flow"). At the time of grant, 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 85% (1)	200%

(1) The performance awards granted prior to 2023 achieved the maximum performance level if the ENLC TSR position relative to designated peer companies was greater than or equal to 75%.

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 have a Cumulative Performance Period). The Board will establish the Cash Flow performance targets 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 2023, the Board adopted the DCF metric as the Cash Flow performance goal in the Performance-Based Award Agreement for all periods beginning after January 1, 2023, rather than the previously used FCFAD metric. The following table sets out the levels at which the Tranche CF Units were eligible to vest (using linear interpolation):

		Performance Period Ended December 31,		
		2023	2022	2021
Performance Level	Vesting Percentage of the Tranche CF Units	Achieved DCF	Achieved FCFAD	Achieved FCFAD
Below Threshold	0%	Less than $801 million	Less than $154 million	Less than $205 million
Threshold	50%	Equal to $801 million	Equal to $154 million	Equal to $205 million
Target	100%	Equal to $932 million	Equal to $202 million	Equal to $256 million
Maximum	200%	Greater than or Equal to $1,123 million	Greater than or Equal to $241 million	Greater than or Equal to $300 million

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 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:

Performance Units:	March 2023	June 2022	March 2022 (1)	January 2021
Grant-date fair value	$ 11.67	$ 11.71	$ 11.90	$ 4.70
Beginning TSR price	$ 10.40	$ 8.54	$ 8.83	$ 3.71
Risk-free interest rate	3.76 %	3.35 %	2.15 %	0.17 %
Volatility factor	64.00 %	76.00 %	75.00 %	71.00 %

(1) Excludes certain performance units awarded March 1, 2022 with vesting conditions based on performance metrics. The 88,863 performance units have a grant-date fair value of $8.90 and were scheduled to vest in February 2023. However, this award partially vested in October 2022 and is reflected in the "Vested" row of the summary of the performance units table below.

The following table presents a summary of the performance units:

	Year Ended December 31, 2023	
Performance Units:	Number of Units	Weighted Average Grant-Date Fair Value
Unvested, beginning of period	2,979,154	$ 6.44
Granted	420,128	11.67
Vested (1)	(1,091,523)	8.30
Forfeited	(71,015)	10.97
Unvested, end of period	2,236,744	$ 6.37
Aggregate intrinsic value, end of period (in millions)	$ 27.2	

(1) Vested units included 811,114 ENLC common 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, 2023, 2022, and 2021 is provided below (in millions).

	Year Ended December 31,		
Performance Units:	**2023**	**2022**	**2021**
Aggregate intrinsic value of units vested	$ 26.1	$ 20.4	$ 0.6
Fair value of units vested	$ 9.1	$ 26.2	$ 4.4

As of December 31, 2023, there were $8.7 million of unrecognized compensation costs that related to unvested performance units. These costs are expected to be recognized over a weighted-average period of 1.4 years.

(d) 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 $8.4 million, $7.4 million, and $7.0 million were made to the plan for the years ended December 31, 2023, 2022, and 2021, respectively.

(13) Derivatives

Interest Rate Swaps

In January 2023, we entered into a $400.0 million interest rate swap to manage the interest rate risk associated with our floating-rate, SOFR-based borrowings, including borrowings on the Revolving Credit Facility and the AR Facility. Under this arrangement, we pay a fixed interest rate of 3.8565% in exchange for SOFR-based variable interest through February 2026. Assets or liabilities related to this interest rate swap contract are included in the fair value of derivative assets and liabilities on the consolidated balance sheets, and the change in fair value of this contract is recorded net as a gain or loss on designated cash flow hedges on the consolidated statements of comprehensive income. Monthly, upon settlement, we reclassify the gain or loss associated with the interest rate swap into interest expense from accumulated other comprehensive income (loss). We designated this interest rate swap as a cash flow hedge in accordance with ASC 815. There is no ineffectiveness related to this hedge.

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. For the year ended December 31, 2021, we terminated $200.0 million of interest rate swaps, resulting in a $1.8 million payment, while the remaining $150.0 million of interest rate swaps expired on December 10, 2021.

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

	Year Ended December 31,		
	2023	**2022**	**2021**
Change in fair value of interest rate swaps	$ 0.9	$ 1.9	$ 18.2
Tax expense	(0.2)	(0.5)	(4.3)
Unrealized gain on designated cash flow hedge	$ 0.7	$ 1.4	$ 13.9

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

	Year Ended December 31,	
	2023	**2022**
Fair value of derivative assets—current	$ 3.3	$ —
Fair value of derivative liabilities—long-term	(2.4)	—
Net fair value of interest rate swaps	$ 0.9	$ —

Interest expense (income) is recognized from accumulated other comprehensive income from the monthly settlement of our interest rate swaps and was included in our consolidated statements of operations as follows (in millions):

	Year Ended December 31,		
	2023	2022	2021
Interest expense (income)	$ (4.5)	$ 1.9	$ 18.3

We expect to recognize an additional $3.3 million of interest income out of accumulated other comprehensive income (loss) over the next twelve months.

Commodity Derivatives

We manage our exposure to changes in commodity prices by hedging the impact of market fluctuations by utilizing various OTC and exchange-traded commodity financial instrument contracts. Commodity swaps and futures 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 or futures 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 natural gas versus first-of-month priced natural 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. Similarly, we use futures in order to mitigate our cash flow exposure to fluctuations in the future prices of natural gas, crude, and condensate. For natural gas, NGLs, condensate, and crude oil, fixed-for-float swaps and futures are used to protect cash flows against price fluctuations: (1) where we receive a percentage of liquids as a fee for processing third-party natural 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 derivatives are as follows (in millions):

	Year Ended December 31,		
	2023	2022	2021
Change in fair value of derivatives	$ (12.1)	$ 40.2	$ (12.4)
Realized gain (loss) on derivatives	32.8	(25.9)	(146.7)
Gain (loss) on derivative activity	$ 20.7	$ 14.3	$ (159.1)

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

	December 31, 2023	December 31, 2022
Fair value of derivative assets—current	$ 73.6	$ 68.4
Fair value of derivative assets—long-term	27.0	2.9
Fair value of derivative liabilities—current	(62.7)	(42.9)
Fair value of derivative liabilities—long-term	(24.3)	(2.7)
Net fair value of commodity derivatives	$ 13.6	$ 25.7

Set forth below are the summarized notional volumes and fair values of all instruments related to commodity derivatives that we held for price risk management purposes and the related physical offsets at December 31, 2023 (in millions, except volumes). The remaining term of the contracts extend no later than January 2028.

		December 31, 2023		
Commodity	**Instruments**	**Unit**	**Volume**	**Net Fair Value**
NGL (short contracts)	Swaps	MMgals	(111.8)	$ (0.8)
NGL (long contracts)	Swaps	MMgals	58.0	1.1
Natural gas (short contracts)	Swaps and futures	Bbtu	(145.8)	86.6
Natural gas (long contracts)	Swaps and futures	Bbtu	122.4	(75.5)
Crude and condensate (short contracts)	Swaps and futures	MMbbls	(7.4)	2.3
Crude and condensate (long contracts)	Swaps and futures	MMbbls	0.1	(0.1)
Total fair value of commodity derivatives				$ 13.6

On all transactions where we are exposed to counterparty risk, we analyze the counterparty's financial condition prior to entering into an agreement, establish limits, and monitor the appropriateness of these limits on an ongoing basis. We primarily deal with 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. Additionally, we have entered into FCDTCs that allow for netting of futures contract receivables and payables in the event of default by either party. If our counterparties failed to perform under existing commodity swap and futures contracts, the maximum loss on our gross receivable position of $100.6 million as of December 31, 2023 would be reduced to $15.2 million due to the offsetting of gross fair value payables against gross fair value receivables as allowed by the ISDAs and the FCDTCs.

(14) Fair Value Measurements

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 and futures contracts, which are not traded on a public exchange. The fair values of commodity swap and futures 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.

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

	Level 2	
	December 31, 2023	December 31, 2022
Interest rate swaps (1)	$ 0.9	$ —
Commodity derivatives (2)	$ 13.6	$ 25.7

(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 derivatives 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, 2023		December 31, 2022	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Long-term debt, including current maturities of long-term debt (1)	$ 4,568.9	$ 4,427.0	$ 4,723.5	$ 4,385.9
Contingent consideration (2)(3)	$ 6.7	$ 6.7	$ 5.5	$ 5.5

(1) The carrying value of long-term debt, including current maturities of long-term debt, is reduced by debt issuance cost, net of accumulated amortization, of $ 32.1 million and $34.9 million as of December 31, 2023 and 2022, respectively. The respective fair values do not factor in debt issuance costs.
(2) Consideration for the Amarillo Rattler Acquisition included a contingent component capped at $15.0 million and payable, if at all, between 2024 and 2026 based on Diamondback E&P LLC’s drilling activity above historical levels. Estimated fair values were calculated using a discounted cash flow analysis that utilized Level 3 inputs.
(3) Consideration for the Central Oklahoma Acquisition included a contingent component, which is payable, if at all, between 2024 and 2027 based on fee revenue earned on certain contractually specified volumes for the annual periods beginning January 1, 2023 through December 31, 2026. Estimated fair values were calculated using a discounted cash flow analysis that utilized Level 3 inputs.

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.

The fair values of all senior unsecured notes as of December 31, 2023 and 2022 were based on Level 2 inputs from third-party market quotations.

(15) Commitments and Contingencies

(a) Change in Control and Severance Agreements

Certain members of our management are parties to severance and change in 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 in 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

In February 2021, the areas in which we operate experienced a severe winter storm, with extreme cold, ice, and snow occurring over an unprecedented period of approximately 10 days ("Winter Storm Uri"). As a result of Winter Storm Uri, we have encountered customer billing disputes related to the delivery of natural gas during the storm, including one that resulted in litigation. The litigation is between one of our subsidiaries, EnLink Gas Marketing, LP ("EnLink Gas"), and Koch Energy Services, LLC ("Koch") in the 162nd District Court in Dallas County, Texas. The dispute centers on whether EnLink Gas was excused from delivering natural gas or performing under certain delivery or purchase obligations during Winter Storm Uri, given our declaration of force majeure during the storm. Koch has invoiced us approximately $53.9 million (after subtracting amounts owed to EnLink Gas) and does not recognize the declaration of force majeure. We believe the declaration of force majeure was valid and appropriate and we intend to vigorously defend against Koch's claims.

One of our subsidiaries, EnLink Energy GP, LLC ("EnLink Energy"), was involved in industry-wide multi-district litigation arising out of Winter Storm Uri, pending in Harris County, Texas, in which multiple individual plaintiffs asserted personal injury and property damage claims arising out of Winter Storm Uri against an aggregate of over 350 power generators, transmission/distribution utility, retail electric provider, and natural gas defendants across over 150 filed cases. On January 26, 2023, the court dismissed the claims against the pipeline and other natural gas-related defendants in the multi-district litigation, including EnLink Energy. The court's order was not appealed and the case is continuing without EnLink Energy and the other natural gas-related defendants. Subsequently, several suits were filed in February 2023 by individual plaintiffs (including one matter in which the plaintiffs seek to certify a class of Texas residents affected by Winter Storm Uri) and the alleged assignee of the claims of individual plaintiffs against approximately 90 natural gas producers, pipelines, marketers, sellers, and traders, including EnLink Gas. EnLink Gas believes it has substantial defenses to these claims and intends to vigorously dispute these allegations and defend against such claims.

In addition, 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. We may also be involved from time to time in the future in various proceedings in the normal course of business, including litigation on disputes related to contracts, property rights, property use or damage (including nuisance claims), personal injury, or the value of pipeline easements or other rights obtained through the exercise of eminent domain or common carrier rights.

(16) Segment Information

We manage and report our operations primarily according to the geography and the nature of the activity. 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 transmission pipelines, natural gas processing plants, natural gas and NGL storage facilities, and fractionation facilities located in Louisiana and, prior to its sale in November 2023, 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 Cana-Woodford, Arkoma-Woodford, northern Oklahoma Woodford, STACK, and adjacent areas;

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

- *Corporate Segment.* The Corporate segment includes our unconsolidated affiliate investments in the Cedar Cove JV in Oklahoma, GCF in South Texas, and the Matterhorn JV in West Texas, as well as our 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, 2023						
Natural gas sales	$ 453.4	$ 444.7	$ 184.5	$ 76.6	$ —	$ 1,159.2
NGL sales	(12.0)	3,031.2	8.5	(6.2)	—	3,021.5
Crude oil and condensate sales	1,250.0	215.6	109.3	—	—	1,574.9
Product sales	1,691.4	3,691.5	302.3	70.4	—	5,755.6
NGL sales—related parties	927.9	22.4	465.6	295.9	(1,711.8)	—
Crude oil and condensate sales—related parties	—	—	—	10.5	(10.5)	—
Product sales—related parties	927.9	22.4	465.6	306.4	(1,722.3)	—
Gathering and transportation	114.6	79.9	236.8	203.9	—	635.2
Processing	60.1	1.6	144.4	123.4	—	329.5
NGL services	—	87.3	—	0.2	—	87.5
Crude services	23.9	19.6	17.5	0.7	—	61.7
Other services	7.3	1.3	0.5	0.8	—	9.9
Midstream services	205.9	189.7	399.2	329.0	—	1,123.8
NGL services—related parties	—	—	—	3.7	(3.7)	—
Midstream services—related parties	—	—	—	3.7	(3.7)	—
Revenue from contracts with customers	2,825.2	3,903.6	1,167.1	709.5	(1,726.0)	6,879.4
Realized gain on derivatives	3.0	2.6	6.5	20.7	—	32.8
Change in fair value of derivatives	(5.0)	4.1	(2.2)	(9.0)	—	(12.1)
Total revenues	2,823.2	3,910.3	1,171.4	721.2	(1,726.0)	6,900.1
Cost of sales, exclusive of operating expenses and depreciation and amortization	(2,205.5)	(3,388.4)	(645.6)	(342.6)	1,726.0	(4,856.1)
Adjusted gross margin	617.7	521.9	525.8	378.6	—	2,044.0
Operating expenses	(221.3)	(130.3)	(103.8)	(102.8)	—	(558.2)
Segment profit	396.4	391.6	422.0	275.8	—	1,485.8
Depreciation and amortization	(166.6)	(151.3)	(217.7)	(115.8)	(5.7)	(657.1)
Gross margin	229.8	240.3	204.3	160.0	(5.7)	828.7
Impairments	—	(20.7)	—	—	—	(20.7)
Gain (loss) on disposition of assets	0.2	(2.0)	0.9	1.2	—	0.3
General and administrative	—	—	—	—	(115.5)	(115.5)
Interest expense, net of interest income	—	—	—	—	(271.7)	(271.7)
Loss from unconsolidated affiliate investments	—	—	—	—	(8.2)	(8.2)
Other loss	—	—	—	—	(0.1)	(0.1)
Income (loss) before non-controlling interest and income taxes	$ 230.0	$ 217.6	$ 205.2	$ 161.2	$ (401.2)	$ 412.8
Capital expenditures	$ 267.3	$ 68.6	$ 69.2	$ 75.5	$ 6.2	$ 486.8

	Permian	Louisiana	Oklahoma	North Texas	Corporate	Totals
Year Ended December 31, 2022						
Natural gas sales	$ 1,078.7	$ 1,128.4	$ 367.5	$ 139.0	$ —	$ 2,713.6
NGL sales	(1.5)	4,196.6	10.8	1.4	—	4,207.3
Crude oil and condensate sales	1,158.6	350.0	135.4	—	—	1,644.0
Product sales	2,235.8	5,675.0	513.7	140.4	—	8,564.9
NGL sales—related parties	1,495.6	97.7	774.6	543.6	(2,911.5)	—
Crude oil and condensate sales—related parties	—	—	0.3	12.3	(12.6)	—
Product sales—related parties	1,495.6	97.7	774.9	555.9	(2,924.1)	—
Gathering and transportation	72.6	75.5	187.5	185.7	—	521.3
Processing	39.2	1.5	119.7	125.9	—	286.3
NGL services	—	82.0	—	0.2	—	82.2
Crude services	21.4	33.3	14.9	0.7	—	70.3
Other services	0.8	1.6	(0.3)	0.7	—	2.8
Midstream services	134.0	193.9	321.8	313.2	—	962.9
NGL services—related parties	—	—	—	1.6	(1.6)	—
Crude services—related parties	—	—	0.1	—	(0.1)	—
Other services—related parties	—	0.2	—	—	(0.2)	—
Midstream services—related parties	—	0.2	0.1	1.6	(1.9)	—
Revenue from contracts with customers	3,865.4	5,966.8	1,610.5	1,011.1	(2,926.0)	9,527.8
Realized gain (loss) on derivatives	(9.0)	2.9	(13.1)	(6.7)	—	(25.9)
Change in fair value of derivatives	9.6	7.7	5.6	17.3	—	40.2
Total revenues	3,866.0	5,977.4	1,603.0	1,021.7	(2,926.0)	9,542.1
Cost of sales, exclusive of operating expenses and depreciation and amortization	(3,280.3)	(5,462.4)	(1,124.4)	(631.7)	2,926.0	(7,572.8)
Adjusted gross margin	585.7	515.0	478.6	390.0	—	1,969.3
Operating expenses	(200.2)	(140.7)	(90.9)	(93.1)	—	(524.9)
Segment profit	385.5	374.3	387.7	296.9	—	1,444.4
Depreciation and amortization	(154.5)	(156.5)	(201.8)	(121.1)	(5.5)	(639.4)
Gross margin	231.0	217.8	185.9	175.8	(5.5)	805.0
Gain (loss) on disposition of assets	0.1	(13.8)	0.5	(4.8)	—	(18.0)
General and administrative	—	—	—	—	(125.2)	(125.2)
Interest expense, net of interest income	—	—	—	—	(245.0)	(245.0)
Loss on extinguishment of debt	—	—	—	—	(6.2)	(6.2)
Loss from unconsolidated affiliate investments	—	—	—	—	(5.6)	(5.6)
Other income	—	—	—	—	0.8	0.8
Income (loss) before non-controlling interest and income taxes	$ 231.1	$ 204.0	$ 186.4	$ 171.0	$ (386.7)	$ 405.8
Capital expenditures	$ 210.2	$ 33.7	$ 63.8	$ 22.8	$ 7.1	$ 337.6

	Permian	Louisiana	Oklahoma	North Texas	Corporate	Totals
Year Ended December 31, 2021						
Natural gas sales	$ 609.4	$ 693.5	$ 213.4	$ 150.0	$ —	$ 1,666.3
NGL sales	0.9	3,353.1	2.0	1.1	—	3,357.1
Crude oil and condensate sales	677.4	212.0	81.2	—	—	970.6
Product sales	1,287.7	4,258.6	296.6	151.1	—	5,994.0
NGL sales—related parties	1,008.4	129.7	630.8	447.0	(2,215.9)	—
Crude oil and condensate sales—related parties	—	—	0.1	7.1	(7.2)	—
Product sales—related parties	1,008.4	129.7	630.9	454.1	(2,223.1)	—
Gathering and transportation	46.8	64.7	186.9	157.0	—	455.4
Processing	29.1	2.4	98.7	108.3	—	238.5
NGL services	—	82.6	—	0.3	—	82.9
Crude services	18.4	39.3	12.8	0.7	—	71.2
Other services	0.2	1.7	0.6	0.5	—	3.0
Midstream services	94.5	190.7	299.0	266.8	—	851.0
Crude services—related parties	—	—	0.3	—	(0.3)	—
Other services—related parties	—	2.4	—	—	(2.4)	—
Midstream services—related parties	—	2.4	0.3	—	(2.7)	—
Revenue from contracts with customers	2,390.6	4,581.4	1,226.8	872.0	(2,225.8)	6,845.0
Realized loss on derivatives	(75.6)	(42.3)	(22.6)	(6.2)	—	(146.7)
Change in fair value of derivatives	(7.7)	0.7	—	(5.4)	—	(12.4)
Total revenues	2,307.3	4,539.8	1,204.2	860.4	(2,225.8)	6,685.9
Cost of sales, exclusive of operating expenses and depreciation and amortization	(1,996.1)	(4,091.2)	(796.6)	(531.8)	2,225.8	(5,189.9)
Adjusted gross margin	311.2	448.6	407.6	328.6	—	1,496.0
Operating expenses	(81.5)	(123.7)	(80.0)	(77.7)	—	(362.9)
Segment profit	229.7	324.9	327.6	250.9	—	1,133.1
Depreciation and amortization	(139.9)	(141.0)	(204.3)	(114.3)	(8.0)	(607.5)
Gross margin	89.8	183.9	123.3	136.6	(8.0)	525.6
Impairments	—	(0.6)	—	—	(0.2)	(0.8)
Gain on disposition of assets	—	1.2	—	0.3	—	1.5
General and administrative	—	—	—	—	(107.8)	(107.8)
Interest expense, net of interest income	—	—	—	—	(238.7)	(238.7)
Loss from unconsolidated affiliate investments	—	—	—	—	(11.5)	(11.5)
Income (loss) before non-controlling interest and income taxes	$ 89.8	$ 184.5	$ 123.3	$ 136.9	$ (366.2)	$ 168.3
Capital expenditures	$ 141.6	$ 9.3	$ 30.4	$ 11.9	$ 2.8	$ 196.0

The table below represents information about segment assets as of December 31, 2023 and 2022 (in millions):

Segment Identifiable Assets:	December 31, 2023	December 31, 2022
Permian	$ 2,813.6	$ 2,661.4
Louisiana	2,031.8	2,310.7
Oklahoma	2,275.8	2,420.4
North Texas	1,017.7	1,094.6
Corporate (1)	189.7	163.9
Total identifiable assets	$ 8,328.6	$ 8,651.0

(1) Accounts receivable and accrued revenue sold to the SPV for collateral under the AR Facility are included within the Permian, Louisiana, Oklahoma, and North Texas segments.

(17) Supplemental Cash Flow Information

The following schedule summarizes cash paid for interest, cash paid (refunded) for income taxes, 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:	**2023**	**2022**	**2021**
Cash paid for interest	$ 266.9	$ 221.1	$ 208.8
Cash paid for income taxes	$ 1.6	$ 0.7	$ 0.3
Cash paid for operating leases included in cash flows from operating activities	$ 35.1	$ 30.5	$ 24.6
Non-cash investing activities:			
Non-cash accrual of property and equipment	$ 41.1	$ 4.2	$ 12.0
Non-cash right-of-use assets obtained in exchange for operating lease liabilities	$ 36.5	$ 33.4	$ 18.7
Non-cash acquisitions	$ —	$ 1.3	$ 16.9
Non-cash financing activities:			
Redemption of mandatorily redeemable non-controlling interest	$ —	$ (6.5)	$ —

(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, 2023	December 31, 2022
Product inventory	$ 46.4	$ 147.1
Prepaid expenses and other	19.0	19.5
Other current assets	$ 65.4	$ 166.6

Other current liabilities:	December 31, 2023	December 31, 2022
Accrued interest	$ 63.4	$ 57.6
Accrued wages and benefits, including taxes	23.2	38.1
Accrued ad valorem taxes	33.3	32.0
Accrued settlement of mandatorily redeemable non-controlling interest (1)	—	10.5
Capital expenditure accruals	64.6	23.4
Short-term lease liability	28.2	26.2
Operating expense accruals	21.5	18.5
Other	44.3	23.3
Other current liabilities	$ 278.5	$ 229.6

(1) In January 2023, we settled the redemption of the mandatorily redeemable non-controlling interest in one of our non-wholly owned subsidiaries.

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, 2023), 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 Exchange Act 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 during the three months ended December 31, 2023 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

Insider Trading Plans

During the three months ended December 31, 2023, no director or officer of the Company adopted a "Rule 10b5-1 trading arrangement" or "non-Rule 10b5-1 trading arrangement" as each term is defined in Item 408(a) of Regulation S-K.

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. Some of the directors of the Managing Member, including directors with a majority of the voting power of the board of directors, are also directors or officers of GIP. 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 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
Jesse Arenivas	50	Chief Executive Officer and Director
Benjamin D. Lamb	44	Executive Vice President and Chief Financial Officer
Walter Pinto	60	Executive Vice President and Chief Operating Officer
Dilanka Seimon	43	Executive Vice President and Chief Commercial Officer
Adam Forman	56	Executive Vice President, General Counsel, and Secretary
Leldon E. Echols (1)	68	Lead Independent Director and Member of the Audit Committee (2), Governance and Compensation Committee, and Conflicts Committee
Deborah G. Adams (1)	63	Director and Member of the Sustainability Committee (2) and Audit Committee
Tiffany Thom Cepak (1)	51	Director and Member of the Audit Committee, Sustainability Committee, and Conflicts Committee (2)
Matthew C. Harris	63	Chairman of the Board and Member of the Governance and Compensation Committee (2)
Scott E. Telesz	56	Director and Member of the Sustainability Committee
Benjamin M. Daniel	40	Director and Member of the Governance and Compensation Committee

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

Jesse Arenivas, has served as the Chief Executive Officer and a director of the Managing Member since June 2022. Prior to June 2022, Mr. Arenivas served as Vice President (President, CO_2 segment) of Kinder Morgan, Inc. (“KMI”) and served in that position since December 2014 where he helped the company grow to become the largest transporter of CO_2 in North America. He was also appointed to President of KMI’s Energy Transition Ventures team upon its formation in February 2021. He joined Kinder Morgan in 2003 and has served in various financial, accounting, and business development roles. Prior to joining KMI, Mr. Arenivas spent five years at ConocoPhillips Co. in financial and commercial roles. Mr. Arenivas received a Bachelor of Business Administration in finance from the University of Texas Permian Basin and is a licensed Certified Public Accountant.

Benjamin D. Lamb, has served as the Executive Vice President and Chief Financial Officer since November 2022. Mr. Lamb previously served in a number of leadership roles, most recently as Executive Vice President and Chief Operating Officer from June 2018 to November 2022, 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.

Walter Pinto, has served as the Executive Vice President and Chief Operating Officer since November 2022. Prior to November 2022, Mr. Pinto served as Senior Vice President, Operation Excellence from March 2020 to November 2022, where he led the optimization of operational and business performance. Prior to March 2020, Mr. Pinto served as a Senior Advisor of Hastings Equity Partners, a private equity firm, supporting Hastings in the sourcing, diligence, and stewardship of existing portfolio companies and new opportunities. He previously spent 25 years at LyondellBasell Industries in various roles, including as Senior Director, Global Projects, Engineering, Turnarounds, Reliability, and Maintenance and head of several manufacturing complexes. Mr. Pinto has served as a board member of industrial service companies and several trade and community organizations. Mr. Pinto received his Master of Science in mechanical engineering from the University of Wisconsin, Milwaukee, and a Bachelor of Science in mechanical engineering from National Institute of Technology in India.

Dilanka Seimon, has served as the Executive Vice President and Chief Commercial Officer since August 2023. In Mr. Seimon's role, he oversees commercial and marketing efforts for the company's traditional midstream and Carbon Solutions businesses. Mr. Seimon has over 20 years of upstream and midstream energy industry experience in strategy and commercial leadership roles across the upstream and midstream energy industries, spanning both traditional hydrocarbon energy and emerging energy sectors, such as carbon capture and storage, renewable fuels, hydrogen, and carbon markets. Mr. Seimon previously served as Vice President of Alternative Energy at Energy Transfer LP, from January 2022 until August 2023. He previously worked at BHP Group Ltd, serving as Vice President Sales and Marketing from July 2019 to December 2021 and as General Manager from January 2017 to June 2019, leading teams responsible for logistics and marketing of BHP's global oil, gas, natural gas liquids, and liquified natural gas production portfolio, as well as procuring power, natural gas, and diesel for BHP's mining assets. Prior to that, he held various roles in natural gas trading, marketing, and origination. Mr. Seimon serves on the Board of Directors of Big Brothers Big Sisters of Greater Houston and the Foundation Board of Trustees of Georgia College & State University, his alma mater where he received a Bachelor of Science in economics. He also earned a Master of Business Administration from Duke University's Fuqua School of Business and is a graduate of the General Management Program at Harvard Business School.

Adam Forman, has served as the Executive Vice President, General Counsel, and Secretary since September 2023. In Mr. Forman's role, he serves on the Executive Leadership Team and leads the legal, and corporate communications departments. Prior to joining EnLink in 2023, Mr. Forman spent almost 24 years at Kinder Morgan, most recently serving as Vice President, Deputy General Counsel, and Secretary where he provided legal counsel on mergers and acquisitions, financing, financial reporting, joint venture, and procurement matters, as well as for the Products Pipelines, Terminals, and CO_2 (Energy Transition Ventures) business segments. As the corporate secretary, he assisted with the company's sustainability initiatives. Prior to Kinder Morgan, he served as an Associate General Counsel at Quanta Services, an infrastructure services company. Mr. Forman earned a Bachelor of Arts in political science from Stanford University and a Juris Doctor from St. Mary's University School of Law. He also holds a Master of Business Administration from Rice University's Jones Graduate School of Business. He serves on the Board of Trustees for the Houston Congregation for Reform Judaism and the Post Oak School.

Leldon E. Echols has served as the Lead Independent Director since March 2023 and as a director of the Managing Member since March 2014. He also previously served as the Chairman of the Board from June 2022 to March 2023. 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 HF Sinclair Corporation. Mr. Echols brings over 40 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 (inactive). 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.

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 ConocoPhillips 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 of Amplify Energy Corp., MRC Global, Inc. and Austin Industries, an employee-owned construction company. Ms. Adams previously served as a director of Gulfport Energy Corporation from March 2018 until May 2021. 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.

Tiffany Thom Cepak has served as a director of the Managing Member since December 2021. Ms. Cepak most recently served as the Chief Financial Officer of Energy XXI Gulf Coast, Inc., an oil and natural gas development and production company, until its sale in October 2018. She also served as the Chief Financial Officer of KLR Energy Acquisition Corp. (and, subsequent to its business combination, Rosehill Resources Inc.) and as Chief Financial Officer of EPL Oil & Gas, Inc. She previously held a number of other positions with EPL, including Treasurer, Director of Investor Relations, and Director of Corporate Reserves. She began her career as a Senior Reservoir Engineer with Exxon Production Co. and Exxon Mobil Co. with operational roles, including reservoir and subsurface completion engineering. Ms. Cepak currently serves on the board of directors of Baytex Energy Corp. Patterson-UTI Energy, Inc., and California Resources Corp., where she serves as Board Chair, and previously served as a director of Yates Petroleum Corp. She holds a Bachelor of Science in engineering from the University of Illinois and a Master of Business Administration from Tulane University. Ms. Cepak was selected to serve as a director due to, among other factors, her extensive experience in the energy sector and her engineering, operational, and finance experience.

Matthew C. Harris, has served as Chairman of the Board and as a director of the Managing Member since March 2023 and previously served as a director from July 2018 until January 2019. Mr. Harris is a Founding Partner of GIP and works with GIP's global energy industry investment team, including crude oil and refined product, natural gas, electricity, LNG, metals and mining, and petrochemicals. He is a member of GIP's Investment, Operating, and Portfolio Valuation Committees. Mr. Harris has been intimately involved in GIP's investment, management, and strategic activities since its formation in 2006. He is a member of the Board of Directors of Freeport LNG, LLC and GE Vernova, the independent public company to be created following its spin-off from General Electric. Prior to the formation of GIP in 2006, Mr. Harris was a Managing Director in the Investment Banking Division of Credit Suisse and Co-Head of the Global Energy Group and Head of the EMEA Emerging Markets Group. Prior to his tenure at Credit Suisse, he was a senior member of the Mergers and Acquisitions Group at Kidder Peabody & Co. Incorporated. Mr. Harris previously served as a director of the general partner of Access Midstream Partners L.P. from January 2010 through December 2013. He holds a B.A. (cum laude) from the University of California at Los Angeles. Mr. Harris was selected to serve as a director due to, among other factors, his investment and strategic experience, his leadership skills, and his experience in mergers and acquisitions.

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, Rio Grande LNG, and Propeller Airports LLC. 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. 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.

Benjamin M. Daniel has served as a director of the Managing Member since April 2022. Mr. Daniel is a Principal at GIP and a key member of GIP's North American energy investment business, focusing on natural gas, crude oil, refined products, and liquified natural gas. He has been a member of GIP's investment team since 2012. Prior to joining GIP, Mr. Daniel was a Vice President at Bluescape Resources, where he was focused on unconventional oil and gas resource investing. Prior to that time, he was a consultant at McKinsey and Company, working primarily with oil and gas clients. He currently serves on the board of directors of Medallion Midstream, a privately held midstream oil and gas company. Mr. Daniel holds a Bachelor of Science with Honors in Mathematics and Master of Arts in Philosophy from Stanford University. Mr. Daniel was selected to serve as a director due to, among other factors, his deep knowledge of the energy industry, his experience in mergers and acquisitions, and his leadership skills.

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 Mr. Echols and Mses. Adams and Cepak 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 four standing committees: the Audit Committee, the Conflicts Committee, the Governance and Compensation Committee, and the Sustainability 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 Mr. Echols (chair) and Mses. Adams and Cepak, 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 Ms. Cepak (chair) and Mr. Echols, 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. 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. Harris (chair), Echols, and Daniel, 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.

The Sustainability Committee, comprised of Ms. Adams (chair), Ms. Cepak, and Mr. Telesz, assists the Board in its general oversight of our environmental, social and governance initiatives, including our environmental, health and safety and operational excellence initiatives, and also provides oversight with respect to identifying, evaluating and monitoring of risks associated with such matters.

Executive Sessions

The non-management directors meet in executive session without management participation at least quarterly. When our Chairman is a member of management, or an affiliate of GIP, we appoint an independent director to preside at such meetings (the "Lead Independent Director"). Currently our Lead Independent Director, Mr. Echols, presides at such executive sessions. Unitholders or interested parties may communicate with non-management directors by sending written communications to the following address to the attention of the Chairman of the Board or Lead Independent 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 Exchange Act 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 2023, 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.

Item 11. Executive Compensation

Governance and Compensation Committee Report

Leldon E. Echols, who serves on the Governance and Compensation Committee of our Board (for purposes of this section, the “Committee”), is an independent director 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:

Matthew C. Harris (chair)

Benjamin M. Daniel

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 is intended to explain 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 after consideration of the recommendations of the Committee. 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

The design of our executive compensation program is intended 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 are intended to 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 80% performance-based compensation, inclusive of equity-based awards issued under our long-term incentive plan and an 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;

- 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 recommends 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 for 2023. 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, severance program design, and employment onboarding considerations, 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 the first quarter of 2023, the Committee decided to initiate a process to evaluate the effectiveness of its current compensation consultant and potentially engage a new compensation consultant. The Committee asked a number of compensation consultants, including Mercer, to participate in a request for proposal process. After reviewing the proposals and interviewing the participating consulting firms, the Committee elected to engage Meridian Compensation Partners, LLC ("Meridian"). Meridian was formally engaged by the Committee in June 2023, and since that time, Meridian has assisted the Committee with compensation items.

Role of Peer Group and Benchmarking

The Committee and Mercer collaborated to identify the following companies as our peer companies in 2023: Crestwood Equity Partners, L.P., DCP Midstream, L.P., Equitrans Midstream Corporation, Genesis Energy, L.P., Magellan Midstream Partners, L.P., MPLX, L.P., NuStar Energy L.P., ONEOK Inc., Targa Resources Corp., Western Midstream Partners, and DT Midstream (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, merger or acquisitions in the industry, 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 2023, 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 in 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 in 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 that are 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 2023 are as follows:

	2023 Base Salary
Jesse Arenivas	$ 725,000
Benjamin D. Lamb	$ 550,000
Walter Pinto	$ 515,000
Dilanka Seimon (1)	$ 500,000
Adam Forman (2)	$ 450,000
Alaina K. Brooks (3)	$ 515,000

(1) In August 2023, the Board appointed Mr. Seimon as Executive Vice President and Chief Commercial Officer.
(2) In September 2023, the Board appointed Mr. Forman as Executive Vice President, General Counsel, and Secretary.
(3) In August 2023, Ms. Brooks departed from her position as Executive Vice President, Chief Legal and Administrative Officer, and Secretary.

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 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 2023, the STI Program included the following Primary Bonus Components:

- *Financial.* Adjusted EBITDA and distributable cash flow ("DCF") to maximize financial performance.
- *Operational Excellence*. Efficient use of systems, assets, and equipment for meeting contractual obligations, driving customer service, and maximizing cash flow.
- *Safety and Sustainability.* Prevention of safety incidents and improvement in safety compliance and training, commitment to environmental compliance, and support of our initiative for more sustainable operations.
- *Capital Projects.* Timely and cost-effective capital projects.

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 2023 Primary Bonus Component and associated information are as follows:

Component	Weighting	Threshold Level	Target Level	Maximum Level
Financial - Adjusted EBITDA	55%	$1,251 million	$1,382 million	$1,574 million
Financial - DCF	10%	$801 million	$932 million	$1,123 million
Operational Excellence	15%		Operational Scorecard	
Safety and Sustainability	15%		Safety and Sustainability Scorecard	
Capital Projects	5%		Timely and cost-effective capital projects	
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 the threshold level results in 0% of target, performance at threshold level results in 50% of target, and performance at the maximum level 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 remain subject to 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, after considering the 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) the 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 bonus amount for each named executive officer is approved by the Board after consideration of the Committee's recommendation and assessment of whether such officer met their personal performance objectives established at the beginning of the performance period. These performance objectives include 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 are reviewed and evaluated by the Committee as a whole. All named executive officers met or exceeded their minimum personal performance objectives for 2023. Accordingly, the Committee and the Board awarded bonuses to the named executive officers as follows:

	Target Bonus Percentage (as a % of Base Salary)	**2023 Bonus (as a % of Base Salary)**	**2023 Bonus Amount ($)**
Jesse Arenivas	125 %	126.7 %	$ 918,245
Benjamin D. Lamb	100 %	109.1 %	$ 600,000
Walter Pinto	90 %	111.7 %	$ 575,000
Dilanka Seimon (1)	90 %	91.8 %	$ 459,000
Adam Forman (2)	90 %	91.8 %	$ 413,100
Alaina K. Brooks (3)	90 %	55.0 %	$ 283,293

(1) In August 2023, the Board appointed Mr. Seimon as Executive Vice President and Chief Commercial Officer.
(2) In September 2023, the Board appointed Mr. Forman as Executive Vice President, General Counsel, and Secretary.
(3) In August 2023, Ms. Brooks departed from her position as Executive Vice President, Chief Legal and Administrative Officer, and Secretary.

Long-Term Incentive Plan. Our named executive officers and outside directors are also eligible to participate in the EnLink Midstream, LLC 2014 Long-Term Incentive Plan (the "2014 Plan"). The Board, after consideration of the recommendations 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, foster a culture of ownership, and are a way to align the interests of executives with those of our unitholders. 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.

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. 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 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 has been amended and restated, resulting in an increase to the number of common units reserved for issuance thereunder. As of December 31, 2023, 24,258,379 common units remain eligible for future grants. 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.

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 our named 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.

Long Term Incentive Awards. 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 in ownership. All performance and restricted incentive units that we grant are charged against earnings according to ASC 718. See "Item 8. Financial Statements and Supplementary Data—Note 12" for more information regarding our long term incentive awards.

Performance Unit Awards. Our performance-based award agreements (the "Performance-Based Award Agreements") provide for future awards of equity-based compensation under the 2014 Plan. Since 2019, the Performance-Based Award Agreements have provided that the vesting of restricted incentive units under the 2014 Plan is dependent on (i) our TSR performance relative to the TSR performance of a peer group of companies and (ii) our cash flow performance, which in previous years has been based on DCF or free cash flow after distributions ("FCFAD") (as applicable, "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"). Beginning in 2023, our Performance-Based Award Agreements were weighted so that Total TSR Units represented 70% of the number of available restricted incentive units and Total CF Units represented 30% of the available restricted incentive units. From 2019 to 2022, our Performance-Based Award Agreements were weighted so that Total TSR Units represented 80% of the number of available restricted incentive units and Total CF Units represented 20% of the available restricted incentive 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 above. 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 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 85% (1)	200%

(1) The performance awards granted prior to 2023 achieved the maximum performance level if the ENLC TSR position relative to designated peer companies was greater than or equal to 75%.

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 have a Cumulative Performance Period). The Board will establish the Cash Flow performance targets 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 2023, the Board adopted the DCF metric as the Cash Flow performance goal in the Performance-Based Award Agreement for all periods beginning after January 1, 2023, rather than the previously used FCFAD metric. We define distributable cash flow as adjusted EBITDA, net to ENLC, plus (less) (interest expense, net of interest income); (maintenance capital expenditures, excluding capital expenditures that were contributed by other entities and relate to the non-controlling interest share of our consolidated entities); (cash distributions earned by the Series B Preferred Units and the Series C Preferred Units); (payment to redeem mandatorily redeemable non-controlling interest); (non-cash gain on lease termination); (earnout payments related to the Amarillo Rattler Acquisition and the Central Oklahoma Acquisition); (payments to terminate interest rate swaps); and (current income tax expense).

The following table sets out the levels at which the Tranche CF Units were eligible to vest (using linear interpolation):

		Performance Period Ended December 31,		
		2023	2022	2021
Performance Level	Vesting Percentage of the Tranche CF Units	Achieved DCF	Achieved FCFAD	Achieved FCFAD
Below Threshold	0%	Less than $801 million	Less than $154 million	Less than $205 million
Threshold	50%	Equal to $801 million	Equal to $154 million	Equal to $205 million
Target	100%	Equal to $932 million	Equal to $202 million	Equal to $256 million
Maximum	200%	Greater than or Equal to $1,123 million	Greater than or Equal to $241 million	Greater than or Equal to $300 million

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.

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 2023, the Operating Partnership matched 100% of every dollar contributed for contributions of up to 6% of eligible compensation made by eligible participants. The retirement benefits provided to the named executive officers were allocated to us as general and administration expenses.

Perquisites and Other Benefits. 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 a de minimis amount per year per named executive officer).

Clawback Policy. We recently adopted a compensation recovery or "clawback" policy in accordance with applicable NYSE listing rules, a copy of which is filed as an exhibit to this Annual Report on Form 10-K. It is generally our policy that the Company will recoup any incentive compensation (annual incentive bonus and performance-based long-term incentives) erroneously awarded to any current or former executive officers due to material noncompliance with any financial reporting requirement under applicable securities laws during the three completed fiscal years immediately preceding the date the Board determines that an accounting restatement is required. Such recoupment would be undertaken by the Company whether or not the executive's actions contributed to the accounting restatement.

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") 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.

The Agreements include restrictions affecting the officers' ability to compete 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 officer 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) their 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 payment 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 their then-current medical insurance benefits for 18 months following the effective date of the termination (the "Medical Severance Benefit").

Potential Payments Upon a Change in 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; each named executive officer 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 their 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 2014 Plan, the amounts to be received by our named executive officers in the event of a change in 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 in 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 in control is periodically reviewed by the Committee.

Upon a change in control, and except as provided in the award agreement, the Committee may cause options and UAR awards to be vested, may cause change in 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 in 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 in control as of December 31, 2023 are set forth in the table in the section below entitled "Payments Upon Termination or Change in Control."

Role of Executive Officers in Executive Compensation. The Board, after consideration of the recommendations 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. Our 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. Our Chief Executive Officer does not make any recommendations regarding his personal compensation.

Unit Ownership Guidelines. Starting in 2024, in order to more closely align the interests of our executive officers and independent directors with those of the Company's other unitholders, our executive officers and independent directors must adhere to unit ownership guidelines. Executive officers are required to hold three times their annual salary of our common units (five times in the case of the Chief Executive Officer) within five years of becoming a named executive officer. Independent directors are required to hold three times their annual cash retainer of our common units within five years of joining the Board. Ownership of our common units include:

- common units owned outright,
- common units held in retirement accounts, savings accounts, and/or trusts,
- unvested restrictive incentive units, and
- any common units deferred in accordance with the deferred compensation plan for our independent directors.

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.

Section 162(m) of the IRC precludes us from taking a tax deduction for individual compensation to certain of our executive officers in excess of $1 million, subject to certain exemptions. While the Committee believes tax deductibility of compensation is an important consideration, the Committee also believes that it is important to retain flexibility in designing compensation programs, and as a result, has not adopted a policy that any particular amount of compensation must be deductible under Section 162(m) of the IRC.

Summary Compensation Table

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

Name and Principal Position	Year	Salary ($)(1)	Non-Equity Incentive Plan Compensation (Bonus)($)(2)	Restricted Incentive Unit and Performance Unit Awards ($) (3)	All Other Compensation ($)	Total ($)
Jesse Arenivas	2023	720,192	918,245	3,500,766	325,930 (7)	5,465,133
Chief Executive Officer	2022	376,923	1,618,750	9,277,314	168,435	11,441,422
Benjamin D. Lamb	2023	546,154	600,000	1,921,791	758,016 (8)	3,825,961
Executive Vice President and Chief Financial Officer	2022	525,577	966,011	2,349,320	426,383	4,267,290
	2021	516,809	852,735	1,984,434	205,645	3,559,623
Walter Pinto	2023	509,423	575,000	1,069,968	239,728 (9)	2,394,119
Executive Vice President and Chief Operating Officer	2022	379,920	436,433	587,331	84,141	1,487,825
Dilanka Seimon (4)	2023	190,385	459,000	2,000,003	271,277 (10)	2,920,665
Executive Vice President and Chief Commercial Officer						
Adam Forman (5)	2023	129,808	413,100	1,231,000	32,300 (11)	1,806,208
Executive Vice President, General Counsel, and Secretary						
Alaina K. Brooks (6)	2023	341,476	283,293	1,194,593	2,571,563 (12)	4,390,925
Former Executive Vice President, Chief Legal and Administrative Officer, and Secretary	2022	481,962	797,261	1,478,091	279,925	3,037,239
	2021	474,039	703,948	1,133,962	185,407	2,497,356

(1) Salary for 2021 included regular earnings and a paid time off payout for Mr. Lamb and Ms. Brooks.
(2) Bonuses include all annual bonus payments paid with respect to the STI Program for the applicable year. All bonuses were paid in cash.
(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 12" for the assumptions made in our valuation of such awards.
(4) In August 2023, the Board appointed Mr. Seimon as Executive Vice President and Chief Commercial Officer.
(5) In September 2023, the Board appointed Mr. Forman as Executive Vice President, General Counsel, and Secretary.
(6) In August 2023, Ms. Brooks departed from her position as Executive Vice President, Chief Legal and Administrative Officer, and Secretary.
(7) Amount of all other compensation for Mr. Arenivas includes a matching 401(k) contribution of $19,800 and DERs with respect to restricted incentive units of ENLC in the amount of $306,130.
(8) Amount of all other compensation for Mr. Lamb includes a matching 401(k) contribution of $19,800 and DERs with respect to restricted incentive units of ENLC in the amount of $738,216.
(9) Amount of all other compensation for Mr. Pinto includes a matching 401(k) contribution of $19,800 and DERs with respect to restricted incentive units of ENLC in the amount of $219,928.
(10) Amount of all other compensation for Mr. Seimon includes DERs with respect to restricted incentive units of ENLC in the amount of $21,277. In connection with his hiring, Mr. Seimon received a cash sign-on bonus of $250,000.
(11) Amount of all other compensation for Mr. Forman includes a matching 401(k) contribution of $19,800 and DERs with respect to restricted incentive units of ENLC in the amount of $12,500.
(12) Amount of all other compensation for Ms. Brooks includes a matching 401(k) contribution of $19,800 and DERs with respect to restricted incentive units of ENLC in the amount of $562,679. Ms. Brooks received $1,989,084 in connection with her departure.

CEO Pay Ratio

For fiscal year 2023, the annual total compensation for Mr. Arenivas was $5.5 million and for the median employee was $142,893. The resulting ratio of annual total compensation of Mr. Arenivas to the annual total compensation of our median employee was 38:1. 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. For 2023, the same median employee as 2022 was used to determine the pay ratio given that there has not been a material change to (i) the employee population, (ii) compensation arrangements believed to result in a significant change to the pay ratio, and (iii) the original median employee's circumstances (e.g., a promotion or demotion). If one of the aforementioned material changes did occur, the same approach used to identify the median employee in 2022 would have been applied for 2023.

To determine the pay ratio, we first identified the median employee by examining 2022 W-2 Box 1 Federal Taxable Wages (the "Taxable Wages Measure") for all of our employees, excluding our Chief Executive Officer, who were employed on December 30, 2022, the last business day of the 2022 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 2022. 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 2023 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 2023 Table

The following table provides information concerning each grant of an award made to a named executive officer for fiscal year 2023.

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)**
Jesse Arenivas	3/22/2023	—	—	—	155,586	(2)	1,684,996
	3/22/2023	77,793	155,586	311,172	—	(3)	1,815,770
Benjamin D. Lamb	3/22/2023	—	—	—	85,411	(2)	925,001
	3/22/2023	42,706	85,411	170,822	—	(3)	996,790
Walter Pinto	3/22/2023	—	—	—	47,553	(2)	514,999
	3/22/2023	23,777	47,553	95,106	—	(3)	554,969
Dilanka Seimon (6)	8/15/2023	—	—	—	170,213	(4)	2,000,003
Adam Forman (7)	9/18/2023	—	—	—	100,000	(5)	1,231,000
Alaina K. Brooks (8)	3/22/2023	—	—	—	53,093	(2)	574,997
	3/22/2023	26,547	53,093	106,186	—	(3)	619,596

(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 12" for the assumptions made in our valuation of such awards.
(2) These grants vest 100% on January 1, 2026, and include DERs that provide for quarterly distributions on restricted incentive units if made on common units during the restriction period, unless otherwise forfeited.
(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, 2026, recipients receive DERs, if any, with respect to the number of performance awards vested.
(4) These grants vest 50% on August 1, 2024, 25% on August 1, 2025, and 25% on August 1, 2026 and include DERs that provide for quarterly distributions on restricted incentive units if made on common units during the restriction period unless otherwise forfeited.
(5) These grants vest 33.3% on September 1, 2024, 33.3% on September 1, 2025, and 33.4% on September 1, 2026 and include DERs that provide for quarterly distributions on restricted incentive units if made on common units during the restriction period unless otherwise forfeited.
(6) In August 2023, the Board appointed Mr. Seimon as Executive Vice President and Chief Commercial Officer.
(7) In September 2023, the Board appointed Mr. Forman as Executive Vice President, General Counsel, and Secretary.
(8) In August 2023, Ms. Brooks departed from her position as Executive Vice President, Chief Legal and Administrative Officer, and Secretary.

Outstanding Equity Awards at Fiscal Year-End Table for Fiscal Year 2023

The following table provides information concerning all outstanding equity awards made to a named executive officer as of December 31, 2023.

ENLINK MIDSTREAM, LLC—OUTSTANDING EQUITY AWARDS AT FISCAL YEAR-END

		Unit Awards			
Name	Vesting Year (1)	Number of Units That Have Not Vested (#)	Market Value of Shares or Units That Have Not Vested ($)(2)	Equity Incentive Plan Awards: Number of Unearned Units or Other Rights that Have Not Vested (#)(3)(4)(5)	Equity Incentive Plan Awards: Market or Payout Value of Unearned Units or Other Rights That Have Not Vested ($)(2)
Jesse Arenivas	2026	155,586	1,891,926	155,586	1,891,926
	2025	310,304	3,773,297	459,364	5,585,866
	2024	146,370	1,779,859	—	—
Benjamin D. Lamb	2026	85,411	1,038,598	85,411	1,038,598
	2025	108,952	1,324,856	108,952	1,324,856
	2024	235,849	2,867,924	235,849	2,867,924
Walter Pinto	2026	47,553	578,244	47,553	578,244
	2025	26,502	322,264	26,502	322,264
	2024	60,647	737,468	60,647	737,468
Dilanka Seimon (6)	2026	42,554	517,457	—	—
	2025	42,553	517,444	—	—
	2024	85,106	1,034,889	—	—
Adam Forman (7)	2026	33,340	405,414	—	—
	2025	33,330	405,293	—	—
	2024	33,330	405,293	—	—
Alaina K. Brooks (8)	2026	—	—	10,812	131,474
	2025	—	—	18,304	222,577
	2024	—	—	54,894	667,511

(1) Restricted incentive units vesting in 2024 and 2025 vest on January 1st, June 1st, August 1st, and September 1st, as applicable. Restricted incentive units vesting in 2026 vest on January 1st, August 1st, and September 1st, as applicable.
(2) The closing price for the ENLC common units was $12.16 as of December 31, 2023.
(3) Reflects the target number of performance units granted to the named executive officers multiplied by a performance percentage of 100%. The actual 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.
(4) Vesting of awards in 2024 and 2025 are contingent upon (i) ENLC's TSR performance measured against a peer group of companies and (ii) ENLC's achieved DCF or ENLC's achieved FCFAD depending on the award and vesting tranche as described above.
(5) Vesting of awards in 2026 is contingent upon (i) ENLC's TSR performance measured against a peer group of companies and (ii) ENLC's achieved DCF.
(6) In August 2023, the Board appointed Mr. Seimon as Executive Vice President and Chief Commercial Officer.
(7) In September 2023, the Board appointed Mr. Forman as Executive Vice President, General Counsel, and Secretary.
(8) In August 2023, Ms. Brooks departed from her position as Executive Vice President, Chief Legal and Administrative Officer, and Secretary. Pursuant to the terms of her award agreements, a portion of Ms. Brooks' outstanding restricted incentive units vested and a portion of her outstanding performance units vested in August 2023. The remaining outstanding performance units not vested in 2023 will vest on the original vesting dates of January 1, 2024, January 1, 2025, and January 1, 2026, as applicable, depending on whether and to what extent the performance metrics thereunder are satisfied.

Units Vested Table for Fiscal Year 2023

The following table provides information related to the vesting of restricted units and restricted incentive units during fiscal year ended 2023.

ENLINK MIDSTREAM, LLC—UNITS VESTED

Name	Date Vested	Number of Units Acquired on Vesting	Value Per Unit Realized on Vesting ($)	Total ($)
Jesse Arenivas	—	—	—	—
Benjamin D. Lamb	1/1/2023	195,749	12.30	2,407,713
	2/1/2023	368,712	12.72	4,690,017
Walter Pinto	1/1/2023	65,789	12.30	809,205
	2/1/2023	123,920	12.72	1,576,262
Dilanka Seimon (1)	—	—	—	—
Adam Forman (2)	—	—	—	—
Alaina K. Brooks (3)	1/1/2023	100,671	12.30	1,238,253
	2/1/2023	189,623	12.72	2,412,005
	8/12/2023	343,940	11.99	4,123,841

(1) In August 2023, the Board appointed Mr. Seimon as Executive Vice President and Chief Commercial Officer.
(2) In September 2023, the Board appointed Mr. Forman as Executive Vice President, General Counsel, and Secretary.
(3) In August 2023, Ms. Brooks departed from her position as Executive Vice President, Chief Legal and Administrative Officer, and Secretary. Pursuant to the terms of her award agreements, a portion of Ms. Brooks' outstanding restricted incentive units vested and a portion of her outstanding performance units vested in August 2023. The remaining outstanding performance units not vested in 2023 will vest on the original vesting dates of January 1, 2024, January 1, 2025, and January 1, 2026, as applicable, depending on whether and to what extent the performance metrics thereunder are satisfied.

Payments Upon Termination or Change in Control

The following table shows potential payments that would have been made to the named executive officers as of December 31, 2023.

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 ($) (3)	Payment Under Change in Control Agreements Upon Termination and Change in Control ($)(4)	Acceleration of Vesting Under Long-Term Incentive Plans Upon Change in Control ($) (5)
Jesse Arenivas	4,236,875	33,081	—	5,052,500	14,922,874
Benjamin D. Lamb	2,811,000	32,508	—	3,361,000	10,462,756
Walter Pinto	2,479,770	1,716	—	2,969,020	3,275,953
Dilanka Seimon	2,409,000	33,081	—	2,884,000	2,069,790
Adam Forman	2,173,100	36,213	—	2,600,600	1,216,000
Alaina K. Brooks (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 they are terminated without cause (as defined in the Severance Agreement) or if they terminate 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 they are terminated without cause (as defined in the applicable Severance Agreement or Change in Control Agreement (the "Applicable Agreement") or if they terminate employment for good reason (as defined in the Applicable Agreement)).

(3) Each named executive officer is entitled to their 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 they are terminated for cause (as defined in the Applicable Agreement) or they terminate 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, the Outplacement Benefit, and when applicable, the bonus amounts comprising the General Benefits will be paid if they are terminated without cause (as defined in the Change in Control Agreement) or if they terminate employment for good reason (as defined in the Change in 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 in 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 2023.

(6) In August 2023, Ms. Brooks departed from her position as Executive Vice President, Chief Legal and Administrative Officer, and Secretary. Pursuant to her departure, Ms. Brooks received a cash payment of $1,989,084 related to her Severance and Health Care Benefits paid in September 2023 and accelerated vesting of outstanding equity awards valued at $4,123,841 as of the vesting date.

Compensation of Directors for Fiscal Year 2023

DIRECTOR COMPENSATION

Name	Fees Earned or Paid in Cash ($)	Unit Awards ($)(1)	All Other Compensation ($)(2)	Total ($)
Leldon E. Echols	165,013	125,000	5,771	295,784
Deborah G. Adams	116,419	125,000	5,771	247,190
Tiffany Thom Cepak (3)	98,806	125,000	5,771	229,577
Kyle D. Vann (4)	61,556	—	—	61,556

(1) On March 22, 2023, Mr. Echols and Mses. Adams and Cepak were each granted awards of restricted incentive units with a fair market value of $10.83 per unit and vested on January 1, 2024. 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 12" for the assumptions made in our valuation of such awards. The number of units granted to each director was based on a unit value of $10.83, the closing trading price on March 21, 2023, and is consistent with the unit value used for grants to Named Executive Officers in the same year. Value on this date represents the Board approved award of equity compensation valued at $125,000. At December 31, 2023, Mr. Echols and Mses. Adams and Cepak each held an aggregate of 11,542 outstanding restricted incentive unit awards. Ms. Cepak's restricted incentive unit awards have been deferred at her election and are subject to vesting under the terms of the EnLink Midstream, LLC 2023 Deferred Compensation Plan.

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

(3) Ms. Cepak elected to defer the compensation related to her unit awards granted on March 22, 2023, and as a result the associated DERs with respect to such restricted incentive units are also deferred.

(4) In March 2023, Mr. Vann retired from his position as a director.

Each director of the Managing Member who is not an employee or partner of the Managing Member or GIP is paid an annual retainer fee of $100,000 except for the Lead Independent Director who is paid an annual retainer of $120,000, and equity compensation valued at $125,000. 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 2023: Audit—$20,000, Governance and Compensation Committee—$20,000, Conflicts—$20,000, and Sustainability—$20,000. Directors were also reimbursed for related out-of-pocket expenses.

Jesse Arenivas, as an officer of the Managing Member, Matthew C. Harris, Scott E. Telesz, and Benjamin M. Daniel, as representatives of GIP, 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 Matthew C. Harris (chair), Benjamin M. Daniels, and Leldon E. Echols. As described elsewhere in this report, Messrs. Harris and Daniels are representatives 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 2023 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 Risk Oversight

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 14, 2024, 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 516,202,942 units (including 62,918,889 common units, which reflects the as-exchanged amount of the outstanding 54,712,077 Series B Preferred Units) as of February 14, 2024.

Name of Beneficial Owner (1)	Common Units Beneficially Owned (2)	Percentage of Common Units Beneficially Owned (3)	Total Units Beneficially Owned (2)	Percentage of Total Units Beneficially Owned (4)
Global Infrastructure Investors III, LLC (5)(6)	208,765,211	46.1 %	208,765,211	40.4 %
ALPS Advisors, Inc. (7)	41,475,283	9.1 %	41,475,283	8.0 %
Invesco Ltd. (8)	23,570,976	5.2 %	23,570,976	4.6 %
Jesse Arenivas	—	*	—	*
Benjamin D. Lamb	512,718	*	512,718	*
Walter Pinto	245,236	*	245,236	*
Dilanka Seimon	—	*	—	*
Adam S. Forman	—	*	—	*
Leldon E. Echols	171,836	*	171,836	*
Deborah G. Adams	81,811	*	81,811	*
Tiffany Thom Cepak	25,087	*	25,087	*
Matthew C. Harris	—	*	—	*
Scott E. Telesz	—	*	—	*
Benjamin M. Daniel	—	*	—	*
All directors and executive officers as a group (11 persons)	1,036,688	*	1,036,688	*

* 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 453,284,053 common units.

(4) The percentages reflected in the column below are based on a total of 516,202,942 common units, which includes the units described in (3) above, and 62,918,889 common units, which reflects the as-exchanged amount of the 54,712,077 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.

(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) Between the filing of Amendment No. 2 to the Schedule 13D filed with the Commission on February 5, 2019 by Global Infrastructure Investors III, LLC and February 14, 2023, we repurchased 7,564,513 and 8,025,635 ENLC common units from Stetson I and Stetson II, respectively, pursuant to our repurchase agreement with GIP. The amount of GIP ENLC common units shown in the table reflects these repurchases. For more information, see "Item 8. Financial Statements and Supplementary Data—Note 5 and Note 10."

(7) As reported on Schedule 13G/A filed with the Commission on February 5, 2024 by ALPS Advisors, Inc. and Alerian MLP ETF each with an address of 1290 Broadway, Suite 1000, Denver, Colorado 80203. The Schedule 13G/A reports that ALPS Advisors, Inc. ("AAI"), an investment adviser registered under the Investment Advisers Act of 1940, as amended, furnishes investment advice to investment companies registered under the Investment Company

Act of 1940, as amended (collectively referred to as the “Funds”). In its role as investment advisor, AAI has voting and/or investment power over the registrant's common units that are owned by the Funds, and may be deemed to be the beneficial owner of such common units held by the Funds. Alerian MLP ETF is an investment company registered under the Investment Company Act of 1940 and is one of the Funds to which AAI provides investment advice. Alerian MLP ETF has shared voting and investment power over 41,475,283 common units. The common units reported herein are owned by the Funds and AAI disclaims beneficial ownership of such common units.

(8) Based solely on the Schedule 13G/A filed with the Commission on February 9, 2024 by Invesco Ltd. (“Invesco”). Such filing indicates that Invesco has sole voting and dispositive power with respect to 23,570,976 ENLC common units. The address of Invesco is 1555 Peachtree Street NE, Suite 1800, Atlanta, GA 30309.

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 GIP’s purchase of equity interests in ENLK, ENLC, and the Managing Member from certain subsidiaries of Devon in 2018 (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 in 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 in control of the Managing Member, which would permit the lenders under ENLC’s Revolving Credit Facility and AR Facility to declare all amounts thereunder due and payable, and it could result in a prepayment event under some of our debt agreements.”

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)	7,682,724 (2)	N/A	24,258,379 (3)
Equity Compensation Plans Not Approved by Security Holders	N/A	N/A	N/A

(1) All securities to be issued under the 2014 Plan, which was approved by our unitholders in March 2014 for the benefit of our officers, employees, and directors.

(2) The number of securities includes 5,445,980 restricted units that have been granted under the 2014 Plan that have not vested. In addition, the number of securities includes 2,236,744 performance unit awards that have been granted under the 2014 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.

(3) The 2014 Plan provided for the issuance of a total of 41,116,046 common units. Of the 41,116,046 common units that may be awarded under the 2014 Plan, 24,258,379 common units remained eligible for future grants as of December 31, 2023.

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

Relationship with EnLink Midstream Partners, LP

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.

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, three of our directors, Matthew C. Harris, Benjamin M. Daniel, and Scott E. Telesz are representatives of GIP, and they control a majority of the voting power on the Board. 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 years ended December 31, 2023 and 2022, we did not record any expense related to transaction with GIP.

GIP Repurchase Agreement. On February 15, 2022, we entered into an agreement with GIP pursuant to which we agreed to repurchase, on a quarterly basis, a pro rata portion of the ENLC common units held by GIP, based upon the number of common units purchased by us during the applicable quarter from public unitholders under our common unit repurchase program. The repurchase agreement terminated as of December 31, 2022 in accordance with its terms.

On December 20, 2022, we entered into the Second Repurchase Agreement on terms substantially similar to those of the repurchase agreement entered into by the Company and GIP on February 15, 2022. The Second Repurchase Agreement terminated on December 31, 2023. On January 16, 2024, we entered into a new repurchase agreement with GIP with terms substantially similar to the Second Repurchase Agreement. The current repurchase agreement will renew for successive one-year terms (each, a "Renewal Year") on January 1 of each Renewal Year, with the first Renewal Year beginning on January 1, 2025, unless either the Company or the GIP Entities elects to terminate the Repurchase Agreement prior to the start of any Renewal Year, during a two-week period in December preceding the applicable Renewal Year. The terms of the repurchase agreement were unanimously approved by the Board and, based upon the related party nature of the repurchase agreement with the GIP Entities, the Conflicts Committee of the Board. For more information regarding our repurchase agreement with GIP, refer to "Item 8. Financial Statements and Supplementary Information—Note 5."

In March 2022, our data center provider since 2009, CyrusOne Inc. ("CyrusOne"), was purchased by an entity that is owned collectively by funds affiliated with GIP and Kohlberg Kravis Roberts & Co. L.P. We paid CyrusOne $0.2 million in fees for data center services for each of the years ended December 31, 2023 and 2022.

Related Party Transactions

Refer to "Item 8. Financial Statements and Supplementary Information—Note 5" for information about our related party transactions.

Certain Relationships

From time to time, we may do business with GIP, companies affiliated with GIP, our board of directors, or with affiliates of our consolidated or unconsolidated joint ventures. 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, 2023, 2022, and 2021, review of our internal control procedures for the fiscal years ended December 31, 2023, 2022, and 2021, 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 $2.8 million, $2.8 million, and $2.5 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, 2023, 2022, and 2021 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, 2023, 2022, and 2021, except for certain tax related services in the amounts of $90.0 thousand and $43.5 thousand for the years ended December 31, 2022 and 2021, respectively, in connection with the preparation of calculations under Internal Revenue Code Section 280G.

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, 2023, 2022, and 2021.

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 chair 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 year ended December 31, 2023, the Audit Committee did not approve additional KPMG audit or non-audit services other than those services covered in the section captioned "Audit Fees." For the years ended December 31, 2022 and 2021, the Audit Committee of the Board pre-approved KPMG providing certain tax related services in the amounts of $90.0 thousand and $43.5 thousand, respectively, for the preparation of calculations under Internal Revenue Code Section 280G.

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
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	—	Eleventh Amended and Restated Agreement of Limited Partnership of EnLink Midstream Partners, LP, dated as of September 8, 2023 (incorporated by reference to Exhibit 3.14 to our Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2023, filed with the Commission on November 1, 2023, 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		—	Second Amended and Restated Registration Rights Agreement, dated as of October 26, 2023, by and among EnLink Midstream, LLC, Patton BIP HoldCo I LLC, Patton BIP HoldCo II LLC and OCM ENLK Holdings, LLC (incorporated by reference to Exhibit 10.1 to our Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2023, filed with the Commission on November 1, 2023, file No. 001-36336).
4.3		—	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).
4.4		—	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).
4.5		—	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).
4.6		—	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).
4.7		—	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).
4.8		—	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).
4.9		—	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).
4.10		—	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).
4.11		—	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).
4.12		—	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).
4.13		—	Indenture, dated as of August 31, 2022, by and among EnLink Midstream, LLC, as issuer, EnLink Midstream Partners, LP, as guarantor, and Computershare Trust Company, N.A., as trustee (incorporated by reference to Exhibit 4.1 to our Current Report on Form 8-K dated August 31, 2022, filed with the Commission on August 31, 2022, 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, LLC 2014 Long-Term Incentive Plan, as amended and restated December 16, 2021 (the "2014 Plan")(incorporated by reference to Exhibit 10.3 to our Annual Report on Form 10-K dated December 31, 2021, filed with the Commission on February 16, 2022, file No. 001-36336).
10.3		—	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).

10.4		—	Amended and Restated Revolving Credit Agreement, dated as of June 3, 2022, by and among EnLink Midstream, LLC, Bank of America, N.A., as Administrative Agent, Swing Line Lender and L/C Issuer, and each of the Lenders and other L/C Issuers party thereto (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K dated June 3, 2022, filed with the Commission on June 6, 2022, file No. 001-36336)
10.5	*†	—	Form of Performance Unit Agreement made under the 2014 Plan.
10.6	†	—	EnLink Midstream, LLC 2023 Deferred Compensation Plan (incorporated by reference to Exhibit 10.3 to our Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2022, filed with the Commission on November 2, 2022, file No. 001-36336).
10.7	†	—	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).
10.8	†	—	Form of EnLink Midstream Operating, LP Amended and Restated Change in Control Agreement (incorporated by reference to Exhibit 10.15 to our Annual Report on Form 10-K dated December 31, 2021, filed with the Commission on February 16, 2022, file No. 001-36336).
10.9		—	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).
10.10		—	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).
10.11		—	First Amendment to the Receivables Financing Agreement, dated as of February 26, 2021, by and among EnLink Midstream Funding, LLC, as borrower, EnLink Midstream Operating, LP, as initial servicer, and PNC Bank, National Association, as administrative agent and as lender (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K dated February 26, 2021, filed with the Commission on March 1, 2021, file No. 001-36336).
10.12		—	Second Amendment to the Receivables Financing Agreement, dated as of September 24, 2021, by and among EnLink Midstream Funding, LLC, as borrower, EnLink Midstream Operating, LP, as initial servicer, and PNC Bank, National Association, as administrative agent and as lender and PNC Capital Markets LLC, as structuring agent and sustainability agent (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K dated September 24, 2021, filed with the Commission on September 27, 2021, file No. 001-36336).
10.13		—	Third Amendment to the Receivables Financing Agreement, dated as of August 1, 2022, by and among EnLink Midstream Funding, LLC, as borrower, EnLink Midstream Operating, LP, as initial servicer, PNC Bank, National Association, as administrative agent and as lender and PNC Capital Markets LLC, as structuring agent and sustainability agent (incorporated by reference to Exhibit 10.2 to our Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2022, filed with the Commission on August 4, 2022, file No. 001-36336).
10.14		—	Unit Repurchase Agreement, dated as of January 16, 2024, between EnLink Midstream, LLC, GIP III Stetson I, L.P. and GIP III Stetson II, L.P. (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K dated January 16, 2024, filed with the Commission on January 16, 2024, 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.
97.1	*†	—	Form of EnLink Midstream Operating, LP Policy Relating to Recovery of Erroneously Awarded Compensation

101	*	—	The following financial information from EnLink Midstream, LLC's Annual Report on Form 10-K for the year ended December 31, 2023, formatted in iXBRL (Inline eXtensible Business Reporting Language): (i) Consolidated Balance Sheets as of December 31, 2023 and December 31, 2022, (ii) Consolidated Statements of Operations for the years ended December 31, 2023, 2022, and 2021, (iii) Consolidated Statements of Changes in Members' Equity for the years ended December 31, 2023, 2022, and 2021, (iv) Consolidated Statements of Cash Flows for the years ended December 31, 2023, 2022, and 2021, and (v) the notes to Consolidated Financial Statements.
104	*	—	Cover Page Interactive Data File (formatted as Inline iXBRL and included in Exhibit 101).

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* Filed herewith.

† As required by Item 15(a)(3), this Exhibit is identified as a management contract or compensatory 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 21, 2024

By: /s/ JESSE ARENIVAS

Jesse Arenivas

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/ JESSE ARENIVAS Jesse Arenivas	Chief Executive Officer and Director (Principal Executive Officer)	February 21, 2024
/s/ DEBORAH G. ADAMS Deborah G. Adams	Director	February 21, 2024
/s/ TIFFANY THOM CEPAK Tiffany Thom Cepak	Director	February 21, 2024
/s/ BENJAMIN M. DANIEL Benjamin M. Daniel	Director	February 21, 2024
/s/ LELDON E. ECHOLS Leldon E. Echols	Lead Independent Director	February 21, 2024
/s/ MATTHEW C. HARRIS Matthew C. Harris	Chairman of the Board and Director	February 21, 2024
/s/ SCOTT E. TELESZ Scott E. Telesz	Director	February 21, 2024
/s/ BENJAMIN D. LAMB Benjamin D. Lamb	Executive Vice President and Chief Financial Officer (Principal Financial Officer)	February 21, 2024
/s/ J. PHILIPP ROSSBACH J. Philipp Rossbach	Vice President and Chief Accounting Officer (Principal Accounting Officer)	February 21, 2024

Exhibit 4.14

ENLINK MIDSTREAM, LLC
DESCRIPTION OF SECURITIES

As of December 31, 2023, EnLink Midstream LLC ("*we*" or "*ENLC*") had 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 and our operating agreement, which are filed as Exhibits 3.1 and 3.3, respectively, to ENLC's Annual Report on Form 10-K for the fiscal year ended December 31, 2023. Our common units are traded on the NYSE under the symbol "ENLC."

Transfer Agent and Registrar

Duties

Equiniti 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.

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 ⅔% of the outstanding common units, including units held by our managing member and its affiliates. See “—Withdrawal or Removal of Our Managing Member.”
Transfer of the interest of our managing member	No approval right. See “—Transfer of Managing Member Interest.”
Transfer of ownership interests in our managing member	No approval right. See “—Transfer of Ownership Interests in Our Managing Member.”

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 the holders of the ENLK Series B Units. The ENLK Series B Units are not entitled to any voting rights with respect to matters that are subject to a vote of the holders of common 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 are 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 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.

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, our operating agreement does not prohibit our subsidiaries from issuing equity interests, which may effectively rank senior to our common units; however, the ENLK Partnership Agreement restricts ENLK's ability to issue any limited partnership interests senior to or on parity with the ENLK Series B Units with respect to distributions on such limited partnership interests or upon liquidation without the affirmative vote of the holders of a majority of the outstanding ENLK Series B Units, voting separately as a class.

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 common units (including common 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 common units in relation to other classes of common units will require the approval of at least a majority of the type or class of common 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 common units constitute not less than the voting requirement sought to be reduced; and
- any amendment that would increase the percentage of common 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 common units, 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 our assets and the assets of our subsidiaries, taken as a whole. 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; provided that any such action with respect to the assets of ENLK may require the approval of the limited partnership interests in ENLK, including the ENLK Series B Units. 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; provided that any such action with respect to the assets of ENLK may require the approval of the limited partnership interests in ENLK, including the ENLK Series B Units. 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 common 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 2/3% of the outstanding common units, including common 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 common units held by our managing member and its affiliates. The ownership of more than 33 1/3% of the voting power of the common 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 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 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 common units of the exercise of this call right are the same as a sale by that unitholder of its common units in the market.

Meetings; Voting

Except as described below regarding a person or group owning 20% or more of any class of units, record holders of common 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 common 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 common units. Unitholders may vote either in person or by proxy at meetings. The holders of a majority of the outstanding common units, represented in person or by proxy, will constitute a quorum, unless any action by the unitholders requires approval by holders of a greater percentage of the units, in which case the quorum will be the greater percentage.

Each record holder of a common 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 units, and the units may not be voted on any matter and will not be considered to be outstanding when sending notices of a meeting of unitholders, calculating required votes, determining the presence of a quorum or for other similar purposes. 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 common 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 U.S. Securities and Exchange Commission (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 4.10 and 4.11 to ENLC's Annual Report on Form 10-K for the fiscal year ended December 31, 2023.

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.

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

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

"*Reference Treasury Dealer*" 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, 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.

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, 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 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.

Exhibit 10.5

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, 2024 and ending on December 31st of that same year;
- The "***Second Performance Period***" shall comprise the period commencing on January 1, 2025 and ending on December 31st of that same year;
- The "***Third Performance Period***" shall comprise the period commencing on January 31, 2026 and ending on December 31st of that same year; and
- The "***Cumulative Performance Period***" shall comprise the period commencing on January 1, 2024 and ending on December 31, 2026.

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 applicable Performance Period to, as applicable, the date of a Qualifying Termination or the date of Retirement (it being understood that once the numerator equals or exceeds the number of days in the applicable Performance Period, the Certified RIUs for such Performance Period shall be considered to have been fully earned and there shall not be any increase to such Certified RIUs and (ii) if the numerator is zero, because the date of the Qualifying Termination or Retirement is prior to the initial date of the applicable Performance Period, no Certified RIUs for such Performance Period shall be earned), and (ii) the denominator of which is the total number of days in the applicable Performance Period; *provided*, *however*, that for the Cumulative Performance Period, such proration calculation shall be done on a year-by-year basis (but shall reflect the Cumulative Performance Period attainment).

"***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. <u>Performance Unit Award</u>. 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. <u>Vesting; Forfeiture</u>.

(a) <u>In General</u>. 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, <u>Schedule B</u>, 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 <u>Schedule B</u> 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) Double Trigger - Advance/Concurrent Change in Control. 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) Double Trigger – Subsequent Change in Control. 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 Performance Period. 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 beginning of the First Performance Period 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

____
Jesse Arenivas
Chief Executive Officer

PARTICIPANT:

____

SCHEDULE A
SUBJECT TRANCHE LISTING[1]

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	[●]

[1] Weighting of TSR to DCF will be 60%/40% of aggregate award.

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 85%	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 "distributable cash flow" ("***DCF***") and shall be calculated consistent with the Company's most relevant published financial results for a given Performance Period (the applicable "***Reference Year***") and means, (A) the Company's Adjusted EBITDA, net to EnLink Midstream LLC, (as defined and calculated consistent with the Company's most relevant published financial results or guidance) minus (B) the sum of (u) interest expense, net of interest income, (v) accrued cash distributions on Series B Preferred Units and Series C Preferred Units paid or expected to be paid, (w) maintenance capital expenditures (excluding maintenance capital expenditures that were contributed by other entities and relate to the non-controlling interest share of the Company's consolidated entities), (x) payments to terminate interest rate swaps, (y) noncash interest income and (z) current income tax expenses, plus (C) noncash interest expense and current income tax benefit. For the avoidance of doubt, actual DCF 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 DCF performance by the Committee for a given Reference Year, Target DCF (as set forth in the chart below) may be adjusted for merger and acquisition activity, large capital growth projects, and any other events or items during the Reference Year that were unforeseen when the performance targets were established. Management shall propose such adjustments for consideration by the Committee. If the Committee, acting in its discretion, approves any such adjustments, the Target DCF 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 DCF for the Performance Period ending December 31, 2024, as compared to the Target DCF as follows:

Performance Level	**Target DCF*‡**	**Associated Individual Payout Level (expressed as a percentage of the Tranche RIUs)**
Below Threshold	Less than $713	0%
Threshold	Equal to $713	50%
Target	Equal to $921	100%
Maximum	Greater than or equal to $1,128	200%

*If the Company's actual achieved DCF is between the Threshold and Target performance levels or if the Company's achieved DCF 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 DCF 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 DCF 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 DCF" 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	Kinetik Holdings, Inc.
Cheniere Energy, Inc.	MPLX, LP
Cheniere Energy Partners, LP	NGL Energy Partners
Delek Logistics Partners, LP	NuStar Energy, LP
DT Midstream	ONEOK, Inc.
Energy Transfer, LP	Plains All American Pipeline, LP
Enterprise Products Partners, LP	Plains GP Holdings
Equitrans Midstream Corp.	Targa Resources Corp.
Genesis Energy, LP	The Williams Companies, Inc.
Hess Midstream Partners LP	Western Gas Equity Partners, LP
Kinder Morgan, Inc.	

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
Cowtown Gas Processing Partners L.P.	Texas
Cowtown Pipeline Partners L.P.	Texas
Delaware G&P LLC	Delaware
Delaware Processing LLC	Delaware
EnLink Barnett Gas Services, LLC	Delaware
EnLink Barnett Gas Services GP, LLC	Delaware
EnLink Calcasieu, LLC	Delaware
EnLink CCS, 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, LLC	Louisiana
EnLink LIG Liquids, LLC	Louisiana
EnLink Louisiana Gathering, LLC	Louisiana
EnLink Matli Holdings, LLC	Delaware
EnLink Midcon, LLC	Delaware
EnLink Midcon Transport, 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 MXP Holding, LLC	Delaware
EnLink NGL Marketing, LP	Texas
EnLink NGL Pipeline, LP	Texas
EnLink Nominee, LLC	Delaware
EnLink North Texas Gathering, LP	Texas
EnLink Oklahoma Crude Gathering, LLC	Delaware
EnLink Oklahoma Gas Processing, LP	Delaware
EnLink Pelican, LLC	Delaware
EnLink Permian, LLC	Texas
EnLink Permian II, LLC	Texas
EnLink Processing Services, LLC	Delaware
EnLink SE Texas Crude Pipeline, 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
Redcliff Midstream, LLC	Delaware
Sabine Ethane, LLC	Delaware
Sabine Hub Services LLC	Delaware

Exhibit 21.1

Sabine Pass Plant Facility Joint Venture	Texas
Sabine Pipe Line LLC	Delaware
SWG Pipeline, L.L.C.	Texas
TOM-STACK, LLC	Delaware

Exhibit 22.1

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>

- 6.50% Senior Notes due September 1, 2030
- 5.375% Senior Notes due June 1, 2029
- 5.625% Senior Notes due January 15, 2028

Exhibit 23.1

Consent of Independent Registered Public Accounting Firm

We consent to the incorporation by reference in the registration statements Nos. 333-194395, 333-229347, 333-229393, and 333-253223 on Form S-8, Nos. 333-229806 and 333-276941 on Form S-3, and No. 333-228278 on Form S-4 of EnLink Midstream, LLC of our report dated February 21, 2024, with respect to the consolidated financial statements of EnLink Midstream, LLC and subsidiaries and the effectiveness of internal control over financial reporting.

/s/ KPMG LLP

Dallas, Texas
February 21, 2024

Exhibit 31.1

CERTIFICATIONS

I, Jesse Arenivas, 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 21, 2024

/s/ JESSE ARENIVAS
Jesse Arenivas
Chief Executive Officer
(principal executive officer)

Exhibit 31.2

CERTIFICATIONS

I, Benjamin D. Lamb, 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 21, 2024

/s/ BENJAMIN D. LAMB
Benjamin D. Lamb
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, 2023 as filed with the Securities and Exchange Commission on the date hereof (the “Report”), each of the undersigned, Jesse Arenivas, Chief Executive Officer of EnLink Midstream Manager, LLC, and Benjamin D. Lamb, 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 21, 2024

/s/ JESSE ARENIVAS
Jesse Arenivas
Chief Executive Officer

Date: February 21, 2024

/s/ BENJAMIN D. LAMB
Benjamin D. Lamb
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.

Exhibit 97.1

ENLINK MIDSTREAM, LLC
POLICY ON RECOUPMENT OF INCENTIVE COMPENSATION

Introduction

The Board of Directors (the "Board") of EnLink Midstream Manager, LLC, a Delaware limited liability company, as the managing member of EnLink Midstream, LLC, a Delaware limited liability company (the "Company"), has adopted this Policy on Recoupment of Incentive Compensation (this "Policy"), which provides for the recoupment of compensation in certain circumstances in the event of a restatement of financial results by the Company. This Policy shall be interpreted to comply with the requirements of U.S. Securities and Exchange Commission ("SEC") rules and New York Stock Exchange ("NYSE") listing standards implementing Section 954 of the Dodd-Frank Wall Street Reform and Consumer Protection Act of 2010 (the "Dodd-Frank Act") and, to the extent this Policy is in any manner deemed inconsistent with such rules, this Policy shall be treated as retroactively amended to be compliant with such rules.

Administration

This Policy shall be administered by the Board. Any determinations made by the Board shall be final and binding on all affected individuals. The Board is authorized to interpret and construe this Policy and to make all determinations necessary, appropriate or advisable for the administration of this Policy, in all cases consistent with the Dodd-Frank Act. The Board may amend this Policy from time to time in its discretion.

Covered Executives

This Policy applies to any current or former "executive officer," within the meaning of Rule 10D-1 under the Securities Exchange Act of 1934, as amended, of the Company or a subsidiary of the Company (each such individual, an "Executive"). This Policy shall be binding and enforceable against all Executives and their beneficiaries, executors, administrators, and other legal representatives.

Recoupment Upon Financial Restatement

If the Company is required to prepare an accounting restatement due to the material noncompliance of the Company with any financial reporting requirement under the securities laws, including any required accounting restatement to correct an error in previously issued financial statements that is material to the previously issued financial statements, or that would result in a material misstatement if the error were corrected in the current period or left uncorrected in the current period (a "Financial Restatement"), the Board shall cause the Company to recoup from each Executive, as promptly as reasonably possible, any erroneously awarded Incentive-Based Compensation, as defined below.

No-Fault Recovery

Recoupment under this Policy shall be required regardless of whether the Executive or any other person was at fault or responsible for accounting errors that contributed to the need for the Financial Restatement or engaged in any misconduct.

Compensation Subject to Recovery; Enforcement

This Policy applies to all compensation granted, earned or vested based wholly or in part upon the attainment of any financial reporting measure determined and presented in accordance with the accounting principles used in preparing the Company's financial statements, and any measure that is derived wholly or in part from such measures, whether or not presented within the Company's financial statements or included in a filing with the SEC, including stock price and total shareholder return ("TSR"), including but not limited to performance-based cash, units, options or other equity-based awards paid or granted to the Executive ("Incentive-Based Compensation"). Compensation that is granted, vests or is earned based solely upon the occurrence of non-financial events, such as base salary, restricted units or options with time-based vesting, or a bonus awarded solely at the discretion of the Board or the Governance and Compensation Committee of the Board (the "Compensation Committee") and not based on the attainment of any financial measure, is not subject to this Policy.

In the event of a Financial Restatement, the amount to be recovered will be the excess of (i) the Incentive-Based Compensation received by the Executive during the Recovery Period (as defined below) based on the erroneous data and calculated without regard to any taxes paid or withheld, over (ii) the Incentive-Based Compensation that would have been received by the Executive had it been calculated based on the restated financial information, as determined by the Board. For purposes of this Policy, "Recovery Period" means the three completed fiscal years immediately preceding the date on which the Company is required to prepare the Financial Restatement, as determined in accordance with the last sentence of this paragraph, or any transition period that results from a change in the Company's fiscal year (as set forth in Section 303A.14(c)(1)(i)(D) of the NYSE Listed Company Manual). The date on which the Company is required to prepare a Financial Restatement is the earlier to occur of (A) the date the Board or a Board committee (or authorized officers of the Company if Board action is not required) concludes, or reasonably should have concluded, that the Company is required to prepare a Financial Restatement or (B) the date a court, regulator, or other legally authorized body directs the Company to prepare a Financial Restatement.

For Incentive-Based Compensation based on stock price or TSR, where the amount of erroneously awarded compensation is not subject to mathematical recalculation directly from the information in the Financial Restatement, then the Board shall determine the amount to be recovered based on a reasonable estimate of the effect of the Financial Restatement on the Share Price or TSR upon which the Incentive-Based Compensation was received and the Company shall document the determination of that estimate and provide it to the NYSE.

Incentive-Based Compensation is considered to have been received by an Executive in the fiscal year during which the applicable financial reporting measure was attained or purportedly attained, even if the payment or grant of such Incentive-Based Compensation occurs after the end of that period.

The Company may use any legal or equitable remedies that are available to the Company to recoup any erroneously awarded Incentive-Based Compensation, including but not limited to by collecting from the Executive cash payments or common units of the Company from or by forfeiting any amounts that the Company owes to the Executive. Executives shall be solely responsible for any tax consequences to them that result from the recoupment or recovery of any amount pursuant to this Policy, and the Company shall have no obligation to administer the Policy in a manner that avoids or minimizes any such tax consequences.

No Indemnification

The Company shall not indemnify any Executive or pay or reimburse the premium for any insurance policy to cover any losses incurred by such Executive under this Policy or any claims relating to the Company's enforcement of rights under this Policy.

Exceptions

The compensation recouped under this Policy shall not include Incentive-Based Compensation received by an Executive (i) prior to beginning service as an Executive or (ii) if he or she did not serve as an Executive at any time during the performance period applicable to the Incentive-Based Compensation in question. A majority of independent directors serving on the Board may determine not to seek recovery from an Executive in whole or part to the extent they determine in their sole discretion that such recovery would be impracticable because (A) the direct expense paid to a third party to assist in enforcing recovery would exceed the recoverable amount (after having made a reasonable attempt to recover the erroneously awarded Incentive-Based Compensation and providing corresponding documentation of such attempt to the NYSE), (B) recovery would violate the home country law that was adopted prior to November 28, 2022, as determined by an opinion of counsel licensed in the applicable jurisdiction that is acceptable to and provided to the NYSE, or (C) recovery would likely cause the Company's 401(k) plan or any other tax-qualified retirement plan to fail to meet the requirements of Section 401(a)(13) or Section 411(a) of the Internal Revenue Code of 1986, as amended, and the regulations thereunder.

Other Remedies Not Precluded

The exercise by the Board of any rights pursuant to this Policy shall be without prejudice to any other rights or remedies that the Company, the Board or the Compensation Committee may have with respect to any Executive subject to this Policy, whether arising under applicable law (including pursuant to Section 304 of the Sarbanes-Oxley Act of 2002), regulation or pursuant to the terms of any other policy of the Company, employment agreement, equity award, cash incentive award or other agreement applicable to an Executive. Notwithstanding the foregoing, there shall be no duplication of recovery of the same Incentive-Based Compensation under this Policy and any other such rights or remedies.

Effective Date and Applicability

This Policy has been adopted by the Board on September 28, 2023, and shall apply to any Incentive-Based Compensation that is received by an Executive on or after October 2, 2023.