QUARTERLY REPORT

CONSOLIDATED FINANCIAL STATEMENTS OF ENLINK MIDSTREAM PARTNERS, LP AND SUBSIDIARIES

For the fiscal year ended March 31, 2024

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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 2. Management’s Discussion and Analysis of Financial Condition and Results of Operations—Non-GAAP Financial Measures” for additional information.
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 718	ASC 718, *Compensation—Stock Compensation*.
ASC 820	ASC 820, *Fair Value Measurements.*
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.
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.
CCS	Carbon capture, transportation, and sequestration.
Cedar Cove JV	Cedar Cove Midstream LLC, 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.
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.
ENLC	EnLink Midstream, LLC together with its consolidated subsidiaries.
ENLK	EnLink Midstream Partners, LP or, when applicable, EnLink Midstream Partners, LP together with its consolidated subsidiaries.
FCDTCs	Futures and Cleared Derivatives Transactions Customer Agreements.
Federal Reserve	The Board of Governors of the Federal Reserve System of the United States.
GAAP	Generally accepted accounting principles in the United States of America.
Gal	Gallon.
GCF	Gulf Coast Fractionators, a joint venture in which we own a 38.75% interest. GCF 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 third quarter of 2024.
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.
ISDAs	International Swaps and Derivatives Association Agreements.
LIBOR	U.S. Dollar London Interbank Offered Rate.
LNG	Liquified natural gas.

Matterhorn JV	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.
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.
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, which were divested in November 2023.
Permian Basin	A large sedimentary basin that includes the Midland and Delaware Basins primarily in West Texas and New Mexico.
PIK Distribution	A quarterly distribution in-kind of Series B Preferred Units. We agreed with the holders of the Series B Preferred Units to make a PIK Distribution until the quarterly distribution in respect of the earlier of (x) any quarter in which the holders of the Series B Preferred Units give notice to our general partner of their election to terminate such PIK Distribution right and (y) the quarter ending June 30, 2024.
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.

PART I—FINANCIAL INFORMATION
Item 1. Financial Statements
ENLINK MIDSTREAM PARTNERS, LP AND SUBSIDIARIES
Consolidated Balance Sheets
(In millions, except unit data)

	March 31, 2024 (Unaudited)	December 31, 2023
ASSETS		
Current assets:		
Cash and cash equivalents	$ 16.8	$ 28.7
Accounts receivable:		
Trade receivables (1)	57.5	85.9
Accrued revenue and other	483.5	581.4
Related party	588.8	506.8
Fair value of derivative assets	90.6	76.9
Other current assets	63.8	65.5
Total current assets	1,301.0	1,345.2
Property and equipment, net of accumulated depreciation of $5,261.6 and $5,137.2, respectively	6,360.4	6,407.0
Intangible assets, net of accumulated amortization of $1,083.0 and $1,051.2, respectively	761.8	793.6
Investment in unconsolidated affiliates	159.8	150.5
Fair value of derivative assets	21.5	27.0
Other assets, net	112.4	112.2
Total assets	$ 8,716.9	$ 8,835.5
LIABILITIES AND PARTNERS' EQUITY		
Current liabilities:		
Accounts payable and drafts payable	$ 113.0	$ 126.5
Accrued natural gas, NGLs, condensate, and crude oil purchases	356.2	428.0
Fair value of derivative liabilities	98.0	62.7
Current maturities of long-term debt	97.9	97.9
Other current liabilities	224.6	239.2
Total current liabilities	889.7	954.3
Long-term debt, net of unamortized issuance cost	4,469.5	4,471.0
Other long-term liabilities	83.5	98.0
Deferred tax liability	3.9	3.9
Fair value of derivative liabilities	21.8	26.7
Partners' equity:		
Common unitholder (144,358,720 units issued and outstanding)	1,377.2	1,423.4
Series B Preferred Unitholders (54,712,077 and 54,575,638 units issued and outstanding, respectively)	805.5	803.5
Series C Preferred Unitholders (366,500 units issued and outstanding)	367.3	367.3
General partner interest (1,594,974 equivalent units outstanding)	223.6	223.4
Accumulated other comprehensive income	4.8	0.9
Non-controlling interest	470.1	463.1
Total partners' equity	3,248.5	3,281.6
Commitments and contingencies (Note 13)		
Total liabilities and partners' equity	$ 8,716.9	$ 8,835.5

(1) There was no allowance for bad debt at March 31, 2024 and December 31, 2023.

See accompanying notes to consolidated financial statements.

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

	Three Months Ended March 31,	
	2024	2023
	(Unaudited)	
Revenues:		
Product sales	$ 1,405.0	$ 1,476.3
Midstream services	271.9	279.3
Gain (loss) on derivative activity	(29.0)	11.9
Total revenues	1,647.9	1,767.5
Operating costs and expenses:		
Cost of sales, exclusive of operating expenses and depreciation and amortization	1,150.4	1,271.9
Operating expenses	152.6	132.4
Depreciation and amortization	165.3	160.4
Impairments	14.2	—
Gain on disposition of assets	(1.7)	(0.4)
General and administrative	55.0	29.3
Total operating costs and expenses	1,535.8	1,593.6
Operating income	112.1	173.9
Other income (expense):		
Interest expense, net of interest income	(65.4)	(68.5)
Loss from unconsolidated affiliate investments	(0.8)	(0.1)
Other income (expense)	0.5	(0.1)
Total other expense	(65.7)	(68.7)
Income before non-controlling interest and income taxes	46.4	105.2
Income tax expense	(0.1)	(0.1)
Net income	46.3	105.1
Net income attributable to non-controlling interest	9.2	10.9
Net income attributable to ENLK	$ 37.1	$ 94.2

See accompanying notes to consolidated financial statements.

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

	Three Months Ended March 31,	
	2024	2023
	(Unaudited)	
Net income	$ 46.3	$ 105.1
Unrealized gain (loss) on designated cash flow hedge	3.9	(1.6)
Comprehensive income	50.2	103.5
Comprehensive income attributable to non-controlling interest	9.2	10.9
Comprehensive income attributable to ENLK	$ 41.0	$ 92.6

See accompanying notes to consolidated financial statements.

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

	Common Units		Series B Preferred Units		Series C Preferred Units		General Partner Interest		Accumulated Other Comprehensive Income (Loss)	Non-Controlling Interest	Total
	$	Units	$	Units	$	Units	$	Units	$	$	$
						(Unaudited)					
Balance, December 31, 2023	$1,423.4	144.4	$803.5	54.6	$367.3	0.4	$223.4	1.6	$ 0.9	$ 463.1	$ 3,281.6
Unit-based compensation	—	—	—	—	—	—	5.6	—	—	—	5.6
Distributions	(62.4)	—	(15.3)	0.1	(9.0)	—	—	—	—	(15.2)	(101.9)
Contributions from non-controlling interests	—	—	—	—	—	—	—	—	—	13.0	13.0
Unrealized gain on designated cash flow hedge	—	—	—	—	—	—	—	—	3.9	—	3.9
Net income (loss)	16.2	—	17.3	—	9.0	—	(5.4)	—	—	9.2	46.3
Balance, March 31, 2024	$1,377.2	144.4	$805.5	54.7	$367.3	0.4	$223.6	1.6	$ 4.8	$ 470.1	$ 3,248.5

See accompanying notes to consolidated financial statements.

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

	Common Units		Series B Preferred Units		Series C Preferred Units		General Partner Interest		Accumulated Other Comprehensive Income (Loss)	Non-Controlling Interest	Total
	$	Units	$	Units	$	Units	$	Units	$	$	$
					(Unaudited)						
Balance, December 31, 2022	$1,373.5	144.4	$799.2	54.2	$380.4	0.4	$220.2	1.6	$ —	$ 426.7	$ 3,200.0
Unit-based compensation	—	—	—	—	—	—	4.0	—	—	—	4.0
Distributions	(61.7)	—	(17.3)	—	(8.4)	—	—	—	—	(16.7)	(104.1)
Contributions from non-controlling interests	—	—	—	—	—	—	—	—	—	8.4	8.4
Unrealized loss on designated cash flow hedge	—	—	—	—	—	—	—	—	(1.6)	—	(1.6)
Repurchase of Series C Preferred Units	—	—	—	—	(3.9)	—	—	—	—	—	(3.9)
Net income (loss)	72.3	—	16.7	—	8.4	—	(3.2)	—	—	10.9	105.1
Balance, March 31, 2023	$1,384.1	144.4	$798.6	54.2	$376.5	0.4	$221.0	1.6	$ (1.6)	$ 429.3	$ 3,207.9

See accompanying notes to consolidated financial statements.

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

	Three Months Ended March 31, 2024	Three Months Ended March 31, 2023
	(Unaudited)	
Cash flows from operating activities:		
Net income	$ 46.3	$ 105.1
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	165.3	160.4
Gain on disposition of assets	(1.7)	(0.4)
Non-cash unit-based compensation	5.6	4.0
Non-cash loss on derivatives recognized in net income	26.1	1.4
Amortization of debt issuance costs and net discount of senior unsecured notes	1.5	1.5
Loss from unconsolidated affiliate investments	0.8	0.1
Impairments	14.2	—
Other operating activities	(1.9)	1.7
Changes in assets and liabilities, net of the effects of acquisitions:		
Accounts receivable, accrued revenue, and other	44.7	24.5
Product inventory, prepaid expenses, and other	11.3	68.5
Accounts payable, accrued product purchases, and other accrued liabilities	(103.0)	(162.9)
Net cash provided by operating activities	209.2	203.9
Cash flows from investing activities:		
Additions to property and equipment	(110.4)	(100.7)
Contributions to unconsolidated affiliate investments	(9.4)	(49.7)
Other investing activities	(5.7)	0.4
Net cash used in investing activities	(125.5)	(150.0)
Cash flows from financing activities:		
Proceeds from borrowings	629.4	1,173.0
Repayments on borrowings	(632.4)	(1,067.4)
Distributions to common unitholders	(62.4)	(61.7)
Distributions to non-controlling interests	(15.2)	(16.7)
Distributions to Series B Preferred Units	(15.3)	(17.3)
Distributions to Series C Preferred Units	(9.0)	(8.4)
Earnout payments	(2.5)	—
Payment to redeem mandatorily redeemable non-controlling interest	—	(10.5)
Repurchase of Series C Preferred Units	—	(3.9)
Contributions from non-controlling interests	13.0	8.4
Other financing activities	(1.2)	0.8
Net cash used in financing activities	(95.6)	(3.7)
Net increase (decrease) in cash and cash equivalents	(11.9)	50.2
Cash and cash equivalents, beginning of period	28.7	22.6
Cash and cash equivalents, end of period	$ 16.8	$ 72.8
Supplemental disclosures of cash flow information:		
Cash paid for interest	$ 65.8	$ 62.2
Non-cash investing activities:		
Right-of-use assets obtained in exchange for operating lease liabilities	$ 11.2	$ 10.4
Non-cash accrual of property and equipment	$ (7.0)	$ 13.4

See accompanying notes to consolidated financial statements.

ENLINK MIDSTREAM PARTNERS, LP AND SUBSIDIARIES
Notes to Consolidated Financial Statements
March 31, 2024
(Unaudited)

(1) General

In this report, the term "Partnership," as well as the terms "ENLK," "our," "we," "us," and "its" are sometimes used as abbreviated references to EnLink Midstream Partners, LP itself or EnLink Midstream Partners, LP together with its consolidated subsidiaries, including the Operating Partnership.

Please read the notes to the consolidated financial statements in conjunction with the Definitions page set forth in this report prior to Part I—Financial Information.

a. Organization of Business

ENLK is a Delaware limited partnership formed in 2002. Our business activities are conducted through the Operating Partnership and the subsidiaries of the Operating Partnership.

EnLink Midstream GP, LLC, a Delaware limited liability company, is our general partner. Our general partner manages our operations and activities. Our general partner is a direct, wholly-owned subsidiary of ENLC. ENLC's units are traded on the New York Stock Exchange under the symbol "ENLC." ENLC's managing member is a wholly-owned subsidiary of GIP. As of March 31, 2024, GIP, through GIP III Stetson I, L.P. and GIP III Stetson II, L.P, owns 45.8% of the outstanding limited liability company interests in ENLC. In addition to their equity interests in ENLC, GIP maintains control over the managing member of ENLC.

b. Nature of Business

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 March 31, 2024, 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.

(2) Significant Accounting Policies

a. Basis of Presentation

The accompanying consolidated financial statements are unaudited and do not include all the information and disclosures required by GAAP for complete financial statements. All adjustments that, in the opinion of management, are necessary for a fair presentation of the results of operations for the interim periods have been made and are of a recurring nature unless otherwise disclosed herein. The results of operations for such interim periods are not necessarily indicative of results of operations for a full year. These consolidated financial statements should be read in conjunction with the consolidated financial statements and accompanying notes included in our Annual Report for the year ended December 31, 2023. 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 partners' equity or net income. All significant intercompany balances and transactions have been eliminated in consolidation.

b. Revenue Recognition

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 minimum 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 (remaining)	$ 116.3
2025	147.9
2026	153.3
2027	125.1
2028	116.4
Thereafter	1,053.0
Total	$ 1,712.0

c. Property and Equipment

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.

During the first quarter of 2024, we identified changes in our outlook for future cash flows and the anticipated use of certain non-core assets in our North Texas segment. We determined that the carrying amounts of these assets exceeded their fair values, based on market inputs and certain assumptions, and recorded an impairment expense of $14.2 million for the three months ended March 31, 2024. In April 2024, we sold these non-core assets in our North Texas segment. We did not record any impairment expense for the three months ended March 31, 2023.

d. Recent Accounting Pronouncements

On November 27, 2023, the FASB issued ASU No. 2023-07, *"Segment Reporting (Topic 280): Improvements to Reportable Segment Disclosures."* ("ASU 2023-07"). ASU 2023-07 amends reportable segment disclosure requirements, primarily through enhanced disclosures about significant segment expenses. This ASU is effective for annual periods beginning after December 15, 2023, and interim periods within fiscal years beginning after December 15, 2024. We do not expect ASU 2023-07 to have a material impact on our financial statements.

On December 14, 2023, the FASB issued ASU No. 2023-09, *"Income Taxes (Topic 740): Improvements to Income Tax Disclosures."* ("ASU 2023-09"). ASU 2023-09 is intended to improve the transparency of income tax disclosures by requiring (i) consistent categories and greater disaggregation of information in the rate reconciliation and (ii) income taxes paid disaggregated by jurisdiction. ASU 2023-09 will become effective for annual periods beginning after December 15, 2024, with early adoption permitted. Management is currently evaluating ASU 2023-09 to determine its impact on the Company's annual disclosures.

(3) 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 (in millions):

	Gross Carrying Amount	Accumulated Amortization	Net Carrying Amount
Three Months Ended March 31, 2024			
Customer relationships, beginning of period	$ 1,844.8	$ (1,051.2)	$ 793.6
Amortization expense	—	(31.8)	(31.8)
Customer relationships, end of period	$ 1,844.8	$ (1,083.0)	$ 761.8

Amortization expense was $31.8 million and $31.9 million for the three months ended March 31, 2024 and 2023, respectively.

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

2024 (remaining)	$ 95.8
2025	110.2
2026	106.3
2027	106.3
2028	106.3
Thereafter	236.9
Total	$ 761.8

(4) Related Party Transactions

(a) Transactions with ENLC

Related Party Debt. Related party debt includes borrowings under the Revolving Credit Facility, $500.0 million in aggregate principal amount of ENLC's 5.625% senior unsecured notes due January 15, 2028 (the "2028 Notes"), $498.7 million in aggregate principal amount of ENLC's 5.375% senior unsecured notes due June 1, 2029 (the "2029 Notes"), and $1.0 billion in aggregate principal amount of ENLC's 6.50% senior unsecured notes due September 1, 2030 (the "2030 Notes") to fund our operations through a related party arrangement with ENLC.

We had related party debt of $2,126.7 million as of March 31, 2024, which consisted of $150.0 million of borrowings under the Revolving Credit Facility and $1,998.7 million related to the 2028 Notes, the 2029 Notes, and the 2030 Notes less $2.6 million discount of senior unsecured notes and $19.4 million of related party debt issuance cost, net of accumulated amortization. We had related party debt of $1,975.5 million as of December 31, 2023, which consisted of $1,998.7 million related to the 2028 Notes, the 2029 Notes, and the 2030 Notes less $2.7 million discount of senior unsecured notes and $20.5 million of related party debt issuance cost, net of accumulated amortization. Related party debt is included in "Long-term debt, net of unamortized issuance cost" in the consolidated balance sheets. See "Note 5—Long-Term Debt" for more information on this arrangement.

Related Party Accounts Receivable. We had accounts receivable balances related to transactions with ENLC of $588.8 million and $506.8 million as of March 31, 2024 and December 31, 2023, respectively.

Related Party Interest Expense, Net of Interest Income. Interest charged to us for borrowings made through the related party arrangement will be the same as interest charged to ENLC on borrowings under the Revolving Credit Facility, the 2028 Notes, the 2029 Notes, and the 2030 Notes, respectively. We incurred related party interest expense of $31.5 million and $32.6 million for the three months ended March 31, 2024 and 2023, respectively.

(b) Transactions with the Cedar Cove JV

We process natural gas and purchase the related residue natural 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:

	March 31, 2024	December 31, 2023
Accrued natural gas, NGLs, condensate, and crude oil purchases	$ 0.3	$ 0.3

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

	Three Months Ended March 31,	
	2024	2023
Midstream services revenue	$ 0.5	$ 0.7
Cost of sales	(1.4)	(1.5)

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.

(5) Long-Term Debt

As of March 31, 2024 and December 31, 2023, long-term debt consisted of the following (in millions):

	March 31, 2024			December 31, 2023		
	Outstanding Principal	Premium (Discount)	Long-Term Debt	Outstanding Principal	Premium (Discount)	Long-Term Debt
Related party debt (1)	$ 2,148.7	$ (2.6)	$ 2,146.1	$ 1,998.7	$ (2.7)	$ 1,996.0
AR Facility due 2025 (2)	147.0	—	147.0	300.0	—	300.0
4.40% Senior unsecured notes due 2024	97.9	—	97.9	97.9	—	97.9
4.15% Senior unsecured notes due 2025	421.6	—	421.6	421.6	—	421.6
4.85% Senior unsecured notes due 2026	491.0	(0.2)	490.8	491.0	(0.2)	490.8
5.60% Senior unsecured notes due 2044	350.0	(0.2)	349.8	350.0	(0.2)	349.8
5.05% Senior unsecured notes due 2045	450.0	(4.9)	445.1	450.0	(5.0)	445.0
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	$ 4,606.2	$ (8.0)	4,598.2	$ 4,609.2	$ (8.2)	4,601.0
Debt issuance cost (3)			(30.8)			(32.1)
Less: Current maturities of long-term debt (4)			(97.9)			(97.9)
Long-term debt, net of unamortized issuance cost			$ 4,469.5			$ 4,471.0

(1) There were $150.0 million outstanding borrowings under the Revolving Credit Facility at March 31, 2024. There were no outstanding borrowings at December 31, 2023.
(2) The effective interest rate was 6.3% and 6.4% at March 31, 2024 and December 31, 2023, respectively.
(3) Net of accumulated amortization of $21.4 million and $20.0 million at March 31, 2024 and December 31, 2023, respectively.
(4) The outstanding balance, net of debt issuance costs, of our 4.40% senior unsecured notes are classified as "Current maturities of long-term debt" on the consolidated balance sheets as of March 31, 2024 and December 31, 2023 as these notes matured on April 1, 2024.

Related Party Debt

The indebtedness under the Revolving Credit Facility, the 2028 Notes, the 2029 Notes, and the 2030 Notes was incurred by ENLC but is guaranteed by us. Therefore, the covenants in the agreements governing such indebtedness described below affect balances owed by us on the related party debt.

Revolving Credit Facility

The Revolving Credit Facility permits ENLC to borrow up to $1.4 billion on a revolving credit basis and includes a $500.0 million letter of credit subfacility. There were $150.0 million in outstanding borrowings under the Revolving Credit Facility and $22.3 million in outstanding letters of credit as of March 31, 2024.

At March 31, 2024, ENLC was in compliance with and expects to be in compliance with the financial covenants of the Revolving Credit Facility for at least the next twelve months. Accordingly, we do not expect to make payments related to our guarantee of the Revolving Credit Facility.

AR Facility

On October 21, 2020, the SPV entered into the AR Facility. We are the primary beneficiary of the SPV, and we consolidate its assets and liabilities, which consist primarily of billed and unbilled accounts receivable of $497.0 million as of March 31, 2024. As of March 31, 2024, the AR Facility had a borrowing base of $389.1 million and there were $147.0 million in outstanding borrowings under the AR Facility.

At March 31, 2024, 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.

(6) Partners' Capital

a. Series B Preferred Units

As of March 31, 2024 and December 31, 2023, there were 54,712,077 and 54,575,638 Series B Preferred Units issued and outstanding, respectively.

Income and Distributions

Income is allocated to the Series B Preferred Units in an amount equal to the quarterly distribution with respect to the period earned. A summary of the distribution activity relating to the Series B Preferred Units during the three months ended March 31, 2024 and 2023 is provided below:

Declaration period	PIK Distribution	Cash distribution (in millions)	Date paid/payable
2024			
Fourth Quarter of 2023	136,439	$ 15.3	February 9, 2024
First Quarter of 2024	130,270	$ 14.7	May 14, 2024
2023			
Fourth Quarter of 2022	—	$ 17.3	February 13, 2023
First Quarter of 2023	135,421	$ 15.2	May 12, 2023

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 us 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 our net income for the allocation year (the "Allocation Cap"). As of March 31, 2024, 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 $7.05 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 we generate positive net income.

b. Series C Preferred Units

As of March 31, 2024 and December 31, 2023, there were 366,500 Series C Preferred Units issued and outstanding.

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
March 15, 2024 – June 14, 2024	9.701 %	$ 9.1	June 17, 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

(1) Distributions on the Series C Preferred Units 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 our general partner out of legally available funds for such purpose.
(2) 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%.

(7) Investment in Unconsolidated Affiliates

As of March 31, 2024, our unconsolidated investments consisted of a 38.75% 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):

	Three Months Ended March 31, 2024	Three Months Ended March 31, 2023
GCF		
Contributions	$ 9.4	$ 6.2
Equity in loss	$ (1.8)	$ (1.1)
Cedar Cove JV		
Distributions	$ —	$ (0.1)
Equity in loss	$ (0.7)	$ (0.6)
Matterhorn JV		
Contributions	$ —	$ 43.5
Equity in income	$ 1.7	$ 1.6
Total		
Contributions	$ 9.4	$ 49.7
Distributions	$ —	$ (0.1)
Equity in loss	$ (0.8)	$ (0.1)

The following table shows the balances related to our investment in unconsolidated affiliates as of March 31, 2024 and December 31, 2023 (in millions):

	March 31, 2024	December 31, 2023
GCF	$ 52.1	$ 44.5
Cedar Cove JV (1)	(8.0)	(7.3)
Matterhorn JV	107.7	106.0
Total investment in unconsolidated affiliates	$ 151.8	$ 143.2

(1) As of March 31, 2024 and December 31, 2023, our investment in the Cedar Cove JV is classified as "Other long-term liabilities" on the consolidated balance sheets.

(8) 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):

	Three Months Ended March 31,	
	2024	2023
Cost of unit-based compensation charged to operating expense	$ 0.9	$ 0.9
Cost of unit-based compensation charged to general and administrative expense	4.7	3.1
Total unit-based compensation expense	$ 5.6	$ 4.0

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 date. A summary of the restricted incentive unit activity for the three months ended March 31, 2024 is provided below:

	Three Months Ended March 31, 2024	
Restricted Incentive Units:	Number of Units	Weighted Average Grant-Date Fair Value
Unvested, beginning of period	5,445,980	$ 7.27
Granted (1)	1,343,217	12.36
Vested (1)(2)	(2,309,954)	3.94
Forfeited	(5,397)	9.96
Unvested, end of period	4,473,846	$ 10.51
Aggregate intrinsic value, end of period (in millions)	$ 61.0	

(1) Beginning in 2024, restricted incentive units awarded typically vest on a graded vesting schedule over three years. Prior to 2024, restricted incentive units awarded typically vested at the end of three years.
(2) Vested units included 680,384 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 three months ended March 31, 2024 and 2023 is provided below (in millions):

	Three Months Ended March 31,	
Restricted Incentive Units:	**2024**	**2023**
Aggregate intrinsic value of units vested	$ 28.1	$ 27.1
Fair value of units vested	$ 9.1	$ 13.4

As of March 31, 2024, there were $29.7 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 2.1 years.

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.

The following table presents a summary of the performance units:

	Three Months Ended March 31, 2024	
Performance Units:	**Number of Units**	**Weighted Average Grant-Date Fair Value**
Unvested, beginning of period	2,236,744	$ 6.37
Granted	508,586	12.92
Vested (1)	(1,061,232)	4.77
Forfeited	(39,052)	11.84
Unvested, end of period	1,645,046	$ 9.30
Aggregate intrinsic value, end of period (in millions)	$ 22.4	

(1) Vested units included 576,040 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 three months ended March 31, 2024 and 2023 is provided below (in millions).

	Three Months Ended March 31,	
Performance Units:	**2024**	**2023**
Aggregate intrinsic value of units vested	$ 19.2	$ 22.0
Fair value of units vested	$ 5.1	$ 8.1

As of March 31, 2024, there were $13.4 million of unrecognized compensation costs that related to unvested performance units. These costs are expected to be recognized over a weighted average period of 2.0 years.

The following table presents a summary of the grant-date fair value assumptions by performance unit grant date:

Performance Units:	February 2024
Grant-date fair value	$ 12.92
Beginning TSR Price	$ 12.74
Risk-free interest rate	4.46 %
Volatility factor	41.51 %

(9) Derivatives

Interest Rate Swap

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. We designated our interest rate swap as a cash flow hedge in accordance with ASC 815, *Derivatives and Hedging*. There is no ineffectiveness related to our hedge.

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

	Three Months Ended March 31,	
	2024	2023
Change in fair value of interest rate swap	$ 3.9	$ (1.6)

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

	March 31, 2024	December 31, 2023
Fair value of derivative assets—current	$ 4.3	$ 3.3
Fair value of derivative assets—long-term	0.5	—
Fair value of derivative liabilities—long-term	—	(2.4)
Net fair value of interest rate swap	$ 4.8	$ 0.9

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

	Three Months Ended March 31,	
	2024	2023
Interest income	$ 1.5	$ 0.5

We expect to recognize an additional $4.3 million of interest income out of accumulated other comprehensive income (loss) over the next twelve months.

Commodity Derivatives

The components of gain (loss) on derivative activity in the consolidated statements of operations related to commodity derivatives are as follows (in millions):

	Three Months Ended March 31, 2024	Three Months Ended March 31, 2023
Change in fair value of derivatives	$ (26.1)	$ (1.4)
Realized gain (loss) on derivatives	(2.9)	13.3
Gain (loss) on derivative activity	$ (29.0)	$ 11.9

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

	March 31, 2024	December 31, 2023
Fair value of derivative assets—current	$ 86.3	$ 73.6
Fair value of derivative assets—long-term	21.0	27.0
Fair value of derivative liabilities—current	(98.0)	(62.7)
Fair value of derivative liabilities—long-term	(21.8)	(24.3)
Net fair value of commodity derivatives	$ (12.5)	$ 13.6

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 March 31, 2024 (in millions, except volumes). The remaining term of the contracts extend no later than January 2028.

Commodity	Instruments	Unit	Volume	Net Fair Value
NGL (short contracts)	Swaps	MMgals	(136.1)	$ (16.3)
NGL (long contracts)	Swaps	MMgals	72.5	(2.1)
Natural gas (short contracts)	Swaps and futures	Bbtu	(143.1)	87.4
Natural gas (long contracts)	Swaps and futures	Bbtu	119.0	(81.4)
Crude and condensate (short contracts)	Swaps and futures	MMbbls	(7.2)	(7.8)
Crude and condensate (long contracts)	Swaps and futures	MMbbls	0.9	7.7
Total fair value of commodity derivatives				$ (12.5)

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 $107.3 million as of March 31, 2024 would be reduced to $4.2 million due to the offsetting of gross fair value payables against gross fair value receivables as allowed by the ISDAs and the FCDTCs.

(10) Fair Value Measurements

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

	Level 2	
	March 31, 2024	December 31, 2023
Interest rate swap (1)	$ 4.8	$ 0.9
Commodity derivatives (2)	$ (12.5)	$ 13.6

(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.

Long-term debt, including current maturities of long-term debt. The carrying value and estimated fair value of our outstanding debt balances are disclosed below (in millions):

	March 31, 2024		December 31, 2023	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Long-term debt, including current maturities of long-term debt (1)	$ 4,567.4	$ 4,424.8	$ 4,568.9	$ 4,427.0

(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 $30.8 million and $32.1 million as of March 31, 2024 and December 31, 2023, respectively. The respective fair values do not factor in debt issuance costs.

The fair values of all senior unsecured notes as of March 31, 2024 and December 31, 2023 were based on Level 2 inputs from third-party market quotations.

Contingent Consideration. The carrying value and estimated fair value of the Amarillo Rattler Acquisition and Central Oklahoma Acquisition contingent consideration liabilities are disclosed below (in millions):

	Three Months Ended March 31, 2024	Three Months Ended March 31, 2023
Amarillo Rattler Acquisition contingent consideration (1)		
Contingent consideration liability, beginning of period	$ 4.8	$ 4.2
Change in fair value	1.4	0.5
Earnout payments	(2.3)	—
Contingent consideration liability, end of period	$ 3.9	$ 4.7
Central Oklahoma Acquisition contingent consideration (2)		
Contingent consideration liability, beginning of period	$ 1.9	$ 1.3
Change in fair value	0.3	0.2
Earnout payments	(0.2)	—
Contingent consideration liability, end of period	$ 2.0	$ 1.5
Total contingent consideration (1)(2)		
Contingent consideration liability, beginning of period	$ 6.7	$ 5.5
Change in fair value	1.7	0.7
Earnout payments	(2.5)	—
Contingent consideration liability, end of period	$ 5.9	$ 6.2

(1) Consideration for the Amarillo Rattler Acquisition included a contingent component capped at $15.0 million and payable between 2024 and 2026 based on Diamondback E&P LLC's drilling activity exceeding historical levels. Estimated fair values were calculated using a discounted cash flow analysis that utilized Level 3 inputs. The carrying value of the contingent consideration is equal to its fair value.

(2) Consideration for the Central Oklahoma Acquisition included a contingent component, which 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. Estimated fair values were calculated using a discounted cash flow analysis that utilized Level 3 inputs. The carrying value of the contingent consideration is equal to its fair value.

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.

(11) 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.

ENLINK MIDSTREAM PARTNERS, LP AND SUBSIDIARIES
Notes to Consolidated Financial Statements (Continued)
(Unaudited)

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 2. 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
Three Months Ended March 31, 2024						
Natural gas sales	$ 104.2	$ 119.6	$ 32.8	$ 24.9	$ —	$ 281.5
NGL sales	(6.6)	768.1	(1.0)	(4.8)	—	755.7
Crude oil and condensate sales	336.6	—	30.9	—	—	367.5
Other	—	—	—	0.3	—	0.3
Product sales	434.2	887.7	62.7	20.4	—	1,405.0
Natural gas sales—related parties	—	0.1	—	—	(0.1)	—
NGL sales—related parties	257.6	9.5	108.7	70.6	(446.4)	—
Crude oil and condensate sales—related parties	—	—	—	3.3	(3.3)	—
Product sales—related parties	257.6	9.6	108.7	73.9	(449.8)	—
Gathering and transportation	39.7	24.4	55.8	45.6	—	165.5
Processing	17.0	0.6	33.6	27.6	—	78.8
NGL services	—	17.3	—	0.1	—	17.4
Crude services	3.8	0.1	3.7	0.2	—	7.8
Other services	1.9	0.1	0.1	0.3	—	2.4
Midstream services	62.4	42.5	93.2	73.8	—	271.9
NGL services—related parties	—	—	—	0.5	(0.5)	—
Midstream services—related parties	—	—	—	0.5	(0.5)	—
Revenue from contracts with customers	754.2	939.8	264.6	168.6	(450.3)	1,676.9
Realized gain (loss) on derivatives	(6.8)	6.4	(1.0)	(1.5)	—	(2.9)
Change in fair value of derivatives	(2.4)	(19.5)	(4.1)	(0.1)	—	(26.1)
Total revenues	745.0	926.7	259.5	167.0	(450.3)	1,647.9
Cost of sales, exclusive of operating expenses and depreciation and amortization	(582.1)	(789.5)	(147.8)	(81.3)	450.3	(1,150.4)
Adjusted gross margin	162.9	137.2	111.7	85.7	—	497.5
Operating expenses	(73.9)	(26.8)	(26.0)	(25.9)	—	(152.6)
Segment profit	89.0	110.4	85.7	59.8	—	344.9
Depreciation and amortization	(43.6)	(35.1)	(56.5)	(28.5)	(1.6)	(165.3)
Gross margin	45.4	75.3	29.2	31.3	(1.6)	179.6
Impairments	—	—	—	(14.2)	—	(14.2)
Gain on disposition of assets	—	1.7	—	—	—	1.7
General and administrative	—	—	—	—	(55.0)	(55.0)
Interest expense, net of interest income	—	—	—	—	(65.4)	(65.4)
Loss from unconsolidated affiliate investments	—	—	—	—	(0.8)	(0.8)
Other income	—	—	—	—	0.5	0.5
Income (loss) before non-controlling interest and income taxes	$ 45.4	$ 77.0	$ 29.2	$ 17.1	$ (122.3)	$ 46.4
Capital expenditures	$ 48.6	$ 31.6	$ 11.8	$ 10.5	$ 0.9	$ 103.4

ENLINK MIDSTREAM PARTNERS, LP AND SUBSIDIARIES
Notes to Consolidated Financial Statements (Continued)
(Unaudited)

	Permian	Louisiana	Oklahoma	North Texas	Corporate	Totals
Three Months Ended March 31, 2023						
Natural gas sales	$ 129.3	$ 131.8	$ 66.8	$ 14.5	$ —	$ 342.4
NGL sales	0.4	857.9	8.6	(1.0)	—	865.9
Crude oil and condensate sales	186.7	56.6	24.7	—	—	268.0
Product sales	316.4	1,046.3	100.1	13.5	—	1,476.3
NGL sales—related parties	237.5	4.4	118.0	79.5	(439.4)	—
Crude oil and condensate sales—related parties	—	—	—	2.7	(2.7)	—
Product sales—related parties	237.5	4.4	118.0	82.2	(442.1)	—
Gathering and transportation	23.3	20.0	54.8	52.1	—	150.2
Processing	14.0	0.3	35.3	32.1	—	81.7
NGL services	—	27.8	—	—	—	27.8
Crude services	6.0	6.5	4.5	0.2	—	17.2
Other services	1.7	0.4	0.1	0.2	—	2.4
Midstream services	45.0	55.0	94.7	84.6	—	279.3
NGL services—related parties	—	—	—	0.6	(0.6)	—
Midstream services—related parties	—	—	—	0.6	(0.6)	—
Revenue from contracts with customers	598.9	1,105.7	312.8	180.9	(442.7)	1,755.6
Realized gain (loss) on derivatives	(4.0)	7.2	2.0	8.1	—	13.3
Change in fair value of derivatives	6.3	(9.0)	(1.4)	2.7	—	(1.4)
Total revenues	601.2	1,103.9	313.4	191.7	(442.7)	1,767.5
Cost of sales, exclusive of operating expenses and depreciation and amortization	(457.1)	(973.9)	(194.0)	(89.6)	442.7	(1,271.9)
Adjusted gross margin	144.1	130.0	119.4	102.1	—	495.6
Operating expenses	(48.1)	(33.6)	(24.7)	(26.0)	—	(132.4)
Segment profit	96.0	96.4	94.7	76.1	—	363.2
Depreciation and amortization	(40.0)	(38.3)	(51.9)	(28.8)	(1.4)	(160.4)
Gross margin	56.0	58.1	42.8	47.3	(1.4)	202.8
Gain on disposition of assets	—	0.1	0.2	0.1	—	0.4
General and administrative	—	—	—	—	(29.3)	(29.3)
Interest expense, net of interest income	—	—	—	—	(68.5)	(68.5)
Loss from unconsolidated affiliate investments	—	—	—	—	(0.1)	(0.1)
Other expense	—	—	—	—	(0.1)	(0.1)
Income (loss) before non-controlling interest and income taxes	$ 56.0	$ 58.2	$ 43.0	$ 47.4	$ (99.4)	$ 105.2
Capital expenditures	$ 56.7	$ 12.3	$ 25.7	$ 18.1	$ 1.3	$ 114.1

The table below represents information about segment assets as of March 31, 2024 and December 31, 2023 (in millions):

Segment Identifiable Assets:	March 31, 2024	December 31, 2023
Permian	$ 2,784.9	$ 2,813.6
Louisiana	1,963.8	2,031.8
Oklahoma	2,214.0	2,275.8
North Texas	962.6	1,017.7
Corporate (1)	791.6	696.6
Total identifiable assets	$ 8,716.9	$ 8,835.5

(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.

(12) 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:	March 31, 2024	December 31, 2023
Product inventory	$ 40.4	$ 46.4
Prepaid expenses and other	23.4	19.1
Other current assets	$ 63.8	$ 65.5

Other current liabilities:	March 31, 2024	December 31, 2023
Accrued interest	$ 43.3	$ 26.5
Accrued wages and benefits, including taxes	12.7	23.2
Accrued ad valorem taxes	12.1	33.3
Capital expenditure accruals	56.3	64.6
Short-term lease liability	32.7	28.2
Operating expense accruals	21.0	21.5
Other	46.5	41.9
Other current liabilities	$ 224.6	$ 239.2

ENLINK MIDSTREAM PARTNERS, LP AND SUBSIDIARIES
Notes to Consolidated Financial Statements (Continued)
(Unaudited)

(13) Commitments and 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. In April 2024, we reached an agreement to settle this matter and dismiss the claims related to this dispute.

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. The plaintiffs asserted claims of tortious interference, nuisance, and unjust enrichment against all defendants and are seeking economic and punitive damages and disgorgement of profits. 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.

Item 2. 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 Part I—Financial Information.

In this report, the term "Partnership," as well as the terms "ENLK," "our," "we," "us," and "its" are sometimes used as abbreviated references to EnLink Midstream Partners, LP itself or EnLink Midstream Partners, LP together with its consolidated subsidiaries, including the Operating Partnership.

Overview

We are a Delaware limited partnership formed on July 12, 2002. We primarily focus on 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 March 31, 2024, 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. 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 three months ended March 31, 2024.

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 three months ended March 31, 2024 and 2023. No other customers represented greater than 10% of our consolidated revenues during the periods presented.

	Three Months Ended March 31,	
	2024	2023
The Dow Chemical Company (1)	10.4 %	11.4 %
Marathon Petroleum Corporation (2)	25.0 %	20.1 %

(1) The Dow Chemical Company together with its consolidated subsidiaries.
(2) Marathon Petroleum Corporation together with its consolidated subsidiaries.

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 crude 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 crude 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.

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)
2024 by quarter:			
1st Quarter	$ 76.91	$ 0.55	$ 2.10
2023 by quarter:			
1st Quarter	$ 75.99	$ 0.61	$ 2.74

(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 Natural Gas Daily closing prices.

Capital markets and the demands of public investors also affect producer behavior, production levels, and our business. In past years, public investors exerted pressure on crude oil and natural gas producers to increase capital discipline and focus on higher investment returns even if it meant 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. However, in response to the rise of crude oil and natural gas prices during 2021 and 2022, capital investments by United States crude oil and natural gas producers have risen, although global capital investments by crude 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.

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 for the last few years, 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 also remained strong. 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 2023. Inflation has moderated in 2023, and the Federal Reserve has signaled an end to rate hikes and may cut rates 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.

Regulatory Developments

On March 6, 2024, the Commission adopted a new set of rules that require a wide range of climate-related disclosures, including material climate-related risks, information on any climate-related targets or goals that are material to the registrant’s business, results of operations, or financial condition, Scope 1 and Scope 2 GHG emissions on a phased-in basis by certain larger registrants when those emissions are material and the filing of an attestation report covering the same, and disclosure of the financial statement effects of severe weather events and other natural conditions including costs and losses. Compliance dates under the final rule are phased in by registrant category. Multiple lawsuits have been filed challenging the Commission’s new climate rules, which have been consolidated and will be heard in the U.S. Court of Appeals for the Eighth Circuit. On April 4, 2024, the Commission issued an order staying the final rules until judicial review is complete.

In accordance with the requirements of the Inflation Reduction Act of 2022, on January 26, 2024, the EPA published its proposed rule regarding the Waste Emissions Charge, applicable to excess methane emissions at certain crude oil and natural gas facilities. Further, On March 8, 2024, the EPA published its final rules imposing new, stricter requirements for methane monitoring, reporting, and emissions control at certain crude oil and natural gas facilities. Finally, on April 10, 2024, the U.S. Bureau of Land Management (“BLM”) published its final Waste Prevention Rule, which requires operators of crude oil and natural gas leases to take reasonable steps to avoid natural gas waste, as well as develop leak detection, repair, and waste minimization plans.

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.

Other Recent Developments

Organic Growth

Henry Hub to the River Project. In 2024, we plan to expand the natural gas transmission capacity of the Bridgeline pipeline from the Henry Hub to the Mississippi River Corridor by 210 MMcf/d through additional compression. We expect to complete the project in the fourth quarter of 2025.

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 relocation in the second quarter of 2024.

GCF Operations. In January 2023, we and our partners started the process to restart the GCF assets. We expect the assets to become operational in the third quarter 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 expect the Matterhorn Express Pipeline to be in service in the third quarter of 2024, pending the receipt of customary regulatory and other approvals.

Rate Reset

Beginning March 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.

Non-GAAP Financial Measures

To assist management in assessing our business, we use the following non-GAAP financial measure: adjusted gross margin.

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):

	Three Months Ended March 31, 2024	Three Months Ended March 31, 2023
Total revenues	$ 1,647.9	$ 1,767.5
Cost of sales, exclusive of operating expenses and depreciation and amortization	(1,150.4)	(1,271.9)
Operating expenses	(152.6)	(132.4)
Depreciation and amortization	(165.3)	(160.4)
Gross margin	179.6	202.8
Operating expenses	152.6	132.4
Depreciation and amortization	165.3	160.4
Adjusted gross margin	$ 497.5	$ 495.6

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
Three Months Ended March 31, 2024						
Total revenues	$ 745.0	$ 926.7	$ 259.5	$ 167.0	$ (450.3)	$ 1,647.9
Cost of sales, exclusive of operating expenses and depreciation and amortization	(582.1)	(789.5)	(147.8)	(81.3)	450.3	(1,150.4)
Adjusted gross margin	162.9	137.2	111.7	85.7	—	497.5
Operating expenses	(73.9)	(26.8)	(26.0)	(25.9)	—	(152.6)
Segment profit	89.0	110.4	85.7	59.8	—	344.9
Depreciation and amortization	(43.6)	(35.1)	(56.5)	(28.5)	(1.6)	(165.3)
Gross margin	$ 45.4	$ 75.3	$ 29.2	$ 31.3	$ (1.6)	$ 179.6

	Permian	Louisiana	Oklahoma	North Texas	Corporate	Totals
Three Months Ended March 31, 2023						
Total revenues	$ 601.2	$ 1,103.9	$ 313.4	$ 191.7	$ (442.7)	$ 1,767.5
Cost of sales, exclusive of operating expenses and depreciation and amortization	(457.1)	(973.9)	(194.0)	(89.6)	442.7	(1,271.9)
Adjusted gross margin	144.1	130.0	119.4	102.1	—	495.6
Operating expenses	(48.1)	(33.6)	(24.7)	(26.0)	—	(132.4)
Segment profit	96.0	96.4	94.7	76.1	—	363.2
Depreciation and amortization	(40.0)	(38.3)	(51.9)	(28.8)	(1.4)	(160.4)
Gross margin	$ 56.0	$ 58.1	$ 42.8	$ 47.3	$ (1.4)	$ 202.8

	Three Months Ended March 31,	
	2024	2023
Midstream Volumes:		
Consolidated		
Gathering and Transportation (MMbtu/d)	7,247,500	7,172,700
Processing (MMbtu/d)	3,505,000	3,469,600
Crude Oil Handling (Bbls/d)	185,100	188,100
NGL Fractionation (Bbls/d)	183,700	183,100
Brine Disposal (Bbls/d)	—	3,000
Permian Segment		
Gathering and Transportation (MMbtu/d)	1,899,300	1,683,700
Processing (MMbtu/d)	1,745,300	1,560,700
Crude Oil Handling (Bbls/d)	164,700	142,600
Louisiana Segment		
Gathering and Transportation (MMbtu/d)	2,753,900	2,693,500
Crude Oil Handling (Bbls/d)	—	18,300
NGL Fractionation (Bbls/d)	183,700	183,100
Brine Disposal (Bbls/d)	—	3,000
Oklahoma Segment		
Gathering and Transportation (MMbtu/d)	1,144,400	1,178,400
Processing (MMbtu/d)	1,090,900	1,164,300
Crude Oil Handling (Bbls/d)	20,400	27,200
North Texas Segment		
Gathering and Transportation (MMbtu/d)	1,449,900	1,617,100
Processing (MMbtu/d)	668,800	744,600

Three Months Ended March 31, 2024 Compared to Three Months Ended March 31, 2023

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 $119.6 million and $121.5 million, respectively, for the three months ended March 31, 2024 compared to the three months ended March 31, 2023 due to the following:

- Product sales revenues decreased $71.3 million for the three months ended March 31, 2024 compared to the three months ended March 31, 2023 primarily due to:

    - A $60.9 million decrease in natural gas sales primarily driven by lower natural gas prices and
    - A $110.2 million decrease in NGL sales primarily driven by lower NGL prices.

  These decreases were partially offset by a $99.5 million increase in crude oil and condensate sales primarily driven by higher crude oil prices.

- The changes in 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 $121.5 million decrease for the three months ended March 31, 2024 compared to the three months ended March 31, 2023.

- Revenues from midstream services decreased $7.4 million for the three months ended March 31, 2024 compared to the three months ended March 31, 2023 primarily due to:

    - A $2.9 million decrease in processing revenues primarily driven by a one-time rate reset to a lower fee on certain existing contracts in our North Texas and Oklahoma segments,
    - A $10.4 million decrease in NGL service revenues primarily driven by lower NGL service volumes, and
    - A $9.4 million decrease in crude services revenues primarily driven by the disposition of our ORV crude assets.

  These decreases were partially offset by a $15.3 million increase in gathering and transportation revenues primarily driven by higher gathering and transportation volumes in our Permian segment.

- Derivative losses increased $40.9 million for the three months ended March 31, 2024 compared to the three months ended March 31, 2023 due to $16.2 million of increased realized losses and $24.7 million of increased unrealized losses.

Operating Expenses. Operating expenses increased $20.2 million for the three months ended March 31, 2024 compared to the three months ended March 31, 2023 primarily due to a $6.4 million increase in construction fees and services, a $5.2 million increase in utilities expense, a $4.5 million increase in compressor rentals, and a $3.6 million increase in materials and supplies expense.

Depreciation and Amortization. Depreciation and amortization increased $4.9 million for the three months ended March 31, 2024 compared to the three months ended March 31, 2023 primarily due to a $6.5 million increase resulting from additional assets being placed in service and a $5.0 million increase related to changes in estimated useful lives. These increases were partially offset by a $4.0 million decrease related to assets reaching the end of their depreciable lives and a $2.7 million decrease due to the divestiture of our ORV assets in November 2023.

Impairments. For the three months ended March 31, 2024, we recognized an impairment expense of $14.2 million due to changes in our outlook for future cash flows and the anticipated use of certain non-core assets in our North Texas segment. We determined that the carrying amounts of these assets exceeded their fair value, based on market inputs and certain assumptions. In April 2024, we sold these non-core assets in our North Texas segment. We did not record any impairment expense for the three months ended March 31, 2023.

General and Administrative Expenses. General and administrative expenses were $55.0 million for the three months ended March 31, 2024 compared to $29.3 million for the three months ended March 31, 2023, an increase of $25.7 million. The increase was primarily due to a $23.3 million increase in loss on litigation settlement, $1.9 million increase in labor and benefits, a $1.0 million increase related to an increase in the estimated fair value of the contingent consideration associated with the Amarillo Rattler Acquisition and the Central Oklahoma Acquisition, and a $1.6 million increase in unit-based compensation. These increases were partially offset by a $2.8 million decrease in office rental costs.

Interest Expense, Net of Interest Income. Interest expense, net of interest income, was $65.4 million for the three months ended March 31, 2024 compared to $68.5 million for the three months ended March 31, 2023, a decrease of $3.1 million. Interest expense, net of interest income, consisted of the following (in millions):

	Three Months Ended March 31, 2024	Three Months Ended March 31, 2023
Senior notes	$ 28.8	$ 28.8
Related party debt	31.5	32.6
AR Facility	5.8	6.2
Amortization of debt issuance costs and net discount of senior unsecured notes	1.5	1.5
Interest rate swap – realized	(1.5)	(0.5)
Other	(0.7)	(0.1)
Interest expense, net of interest income	$ 65.4	$ 68.5

Loss from Unconsolidated Affiliate Investments. Loss from unconsolidated affiliate investments was $0.8 million for the three months ended March 31, 2024 compared to $0.1 million for the three months ended March 31, 2023, an increase in loss of $0.7 million. The increase in loss was primarily attributable to a $0.7 million increase in loss related to our GCF investment and a $0.1 million increase in loss related to the Cedar Cove JV. This increase in loss was partially offset by a $0.1 million increase in income related to the Matterhorn JV.

Net Income Attributable to Non-Controlling Interest. Net income attributable to non-controlling interest was $9.2 million for the three months ended March 31, 2024 compared to net income of $10.9 million for the three months ended March 31, 2023, a decrease of $1.7 million. Our non-controlling interest is comprised of NGP's 49.9% share of the Delaware Basin JV and Marathon Petroleum Corporation's 50% share of the Ascension JV. The decrease in income was primarily due to a $1.6 million decrease in income attributable to NGP's 49.9% share of the Delaware Basin JV and a $0.1 million decrease in income attributable to Marathon Petroleum Corporation's 50% share of the Ascension JV.

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 three months ended March 31, 2024 compared to the three months ended March 31, 2023.

- *Permian Segment.*
  - Revenues and cost of sales, exclusive of operating expenses and depreciation and amortization, increased $143.8 million and $125.0 million, respectively, resulting in an increase in adjusted gross margin in the Permian segment of $18.8 million, due to:
    - A $14.9 million increase in adjusted gross margin associated with our Permian natural gas assets. Adjusted gross margin, excluding derivative activity, increased $29.0 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 $14.1 million, which included $4.9 million from increased realized losses and $9.2 million from increased unrealized losses.
    - A $3.9 million increase in adjusted gross margin associated with our Permian crude assets. Adjusted gross margin, excluding derivative activity, increased $1.3 million, which was primarily due to higher volumes from existing customers. Derivative activity associated with our Permian crude assets increased adjusted gross margin by $2.6 million, which included $2.1 million from increased realized gains and $0.5 million from increased unrealized gains.
  - Operating expenses in the Permian segment increased $25.8 million primarily due to an $8.6 million increase in utilities expense, a $6.8 million increase in construction fees and services, a $4.3 million increase in compressor rentals, a $3.3 million increase in materials and supplies expense, and a $2.7 million increase in labor and benefits costs.
  - Depreciation and amortization in the Permian segment increased $3.6 million primarily due to additional assets being placed in service.
- *Louisiana Segment.*
  - Revenues and cost of sales, exclusive of operating expenses and depreciation and amortization, decreased $177.2 million and $184.4 million, respectively, resulting in an increase in adjusted gross margin in the Louisiana segment of $7.2 million, due to:
    - A $6.2 million decrease in adjusted gross margin associated with our Louisiana NGL transmission and fractionation assets. Adjusted gross margin, excluding derivative activity, decreased $1.0 million, which was primarily due to lower seasonal fees for delivery of normal butane. Derivative activity associated with our Louisiana NGL transmission and fractionation assets decreased adjusted gross margin by $5.2

million, which included $3.5 million from increased realized losses and $1.7 million from increased unrealized losses.
- A $24.1 million increase in adjusted gross margin associated with our Louisiana natural gas assets. Adjusted gross margin, excluding derivative activity, increased $29.1 million, which was primarily due to price fluctuations during inclement weather. Derivative activity associated with our Louisiana natural gas assets decreased adjusted gross margin by $5.0 million, which included $3.8 million from increased realized gains and $8.8 million from increased unrealized losses.
- A $10.7 million decrease in adjusted gross margin associated with our ORV crude assets, which was due to the divestitures of our ORV assets in our Louisiana segment in November 2023.

◦ Operating expenses in the Louisiana segment decreased $6.8 million primarily due to a $2.0 million decrease in labor and benefits costs, a $1.9 million decrease in utilities expense, a $1.5 million decrease in vehicle expenses related to the disposal of the heavy truck fleet in ORV, a $0.5 million decrease in construction fees and services, a $0.4 million decrease in compressor overhauls, and a $0.4 million decrease in insurance costs.

◦ Depreciation and amortization in the Louisiana segment decreased $3.2 million primarily due to a $2.7 million decrease resulting from assets reaching the end of their depreciable lives and a $2.7 million decrease due to the divestitures of our ORV assets in November 2023, partially offset by a $1.2 million increase due to additional assets being placed in service and $1.0 million increase due to changes in estimated useful lives.

- *Oklahoma Segment.*

- Revenues and cost of sales, exclusive of operating expenses and depreciation and amortization, decreased $53.9 million and $46.2 million, respectively, resulting in a decrease in adjusted gross margin in the Oklahoma segment of $7.7 million, due to:

  - A $6.8 million decrease in adjusted gross margin associated with our Oklahoma natural gas assets. Adjusted gross margin, excluding derivative activity, decreased $1.4 million, which was primarily due to lower volumes from existing customers. Derivative activity associated with our Oklahoma natural gas assets decreased adjusted gross margin by $5.4 million, which included $2.7 million from increased realized losses and $2.7 million from increased unrealized losses.
  - A $0.9 million decrease in adjusted gross margin associated with our Oklahoma crude assets. Adjusted gross margin, excluding derivative activity, decreased $0.6 million, which was primarily due to lower volumes from existing customers. Derivative activity associated with our Oklahoma crude assets decreased adjusted gross margin by $0.3 million from increased realized losses.

◦ Operating expenses in the Oklahoma segment increased $1.3 million primarily due to a $0.9 million increase in ad valorem taxes, a $0.8 million increase in construction fees and services, a $0.4 million increase in materials and supplies expense, and a $0.4 million increase in labor and benefits costs. These increases were partially offset by a $1.1 million decrease in utilities expense.

◦ Depreciation and amortization in the Oklahoma segment increased $4.6 million primarily due to a $4.1 million increase resulting from changes in estimated useful lives and a $0.6 million increase due to additional assets being placed in service.

- *North Texas Segment.*

◦ Revenues and cost of sales, exclusive of operating expenses and depreciation and amortization, decreased $24.7 million and $8.3 million, respectively, resulting in a decrease in adjusted gross margin in the North Texas segment of $16.4 million. Adjusted gross margin, excluding derivative activity, decreased $4.0 million, which was primarily due to lower volumes from existing customers. Derivative activity associated with our North Texas segment decreased adjusted gross margin by $12.4 million, which included $9.6 million from increased realized losses and $2.8 million from increased unrealized losses.

◦ Operating expenses in the North Texas segment decreased $0.1 million primarily due to a $0.6 million decrease in construction fees and services, a $0.3 million decrease in materials and supplies expense, and a $0.2 million decrease in ad valorem taxes. These decreases were partially offset by a $1.1 million increase in expenses related to compressor overhauls.

- ◦ Depreciation and amortization in the North Texas segment decreased $0.3 million primarily due to a $1.3 million decrease due to assets reaching the end of their depreciable lives, partially offset by a $0.9 million increase due to additional assets being placed in service.

- *Corporate Segment.*

  - ◦ Revenues and cost of sales, exclusive of operating expenses and depreciation and amortization, each decreased $7.6 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 being placed in service.

Critical Accounting Policies

Information regarding our critical accounting policies is included in "Item 1. Management's Discussion and Analysis of Financial Condition and Results of Operations" of our Annual Report for the year ended December 31, 2023.

Liquidity and Capital Resources

Cash Flows from Operating Activities. Net cash provided by operating activities was $209.2 million for the three months ended March 31, 2024 compared to $203.9 million for the three months ended March 31, 2023. Operating cash flows before working capital and changes in working capital for the comparative periods were as follows (in millions):

	Three Months Ended March 31,	
	2024	2023
Operating cash flows before working capital	$ 256.2	$ 273.8
Changes in working capital	(47.0)	(69.9)

Operating cash flows before changes in working capital decreased $17.6 million for the three months ended March 31, 2024 compared to the three months ended March 31, 2023. The primary contributor to the decrease in operating cash flows before working capital is as follows:

- Gross margin, excluding depreciation and amortization, non-cash commodity derivative activity, utility credits redeemed, and unit-based compensation, increased $5.0 million. The increase in gross margin is due to a $26.6 million increase in adjusted gross margin, excluding non-cash commodity derivative activity, which was partially offset by a $21.6 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 three months ended March 31, 2024 compared to the three months ended March 31, 2023, see "Results of Operations."

The changes in working capital for the three months ended March 31, 2024 compared to the three months ended March 31, 2023 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.

Cash Flows from Investing Activities. Net cash used in investing activities was $125.5 million for the three months ended March 31, 2024 compared to $150.0 million for the three months ended March 31, 2023. Our primary investing activities consisted of the following (in millions):

	Three Months Ended March 31,	
	2024	2023
Additions to property and equipment (1)	$ (110.4)	$ (100.7)
Contributions to unconsolidated affiliate investments (2)	(9.4)	(49.7)

(1) The increase in capital expenditures was due to expansion projects to accommodate increased volumes on our systems.
(2) Represents contributions to the Matterhorn JV and GCF. See "Item 1. Financial Statements—Note 7" for more information regarding the contributions to unconsolidated affiliate investments.

Cash Flows from Financing Activities. Net cash used in financing activities was $95.6 million for the three months ended March 31, 2024 compared to $3.7 million for the three months ended March 31, 2023. Our primary financing activities consisted of the following (in millions):

	Three Months Ended March 31,	
	2024	2023
Net repayments on the AR Facility (1)	$ (153.0)	$ (144.4)
Net borrowings on related party debt (1)	150.0	250.0
Distributions to common units (2)	(62.4)	(61.7)
Distributions to Series B Preferred Unitholders (3)	(15.3)	(17.3)
Distributions to Series C Preferred Unitholders (3)	(9.0)	(8.4)
Distributions to non-controlling interests (4)	(15.2)	(16.7)
Earnout payments (5)	(2.5)	—
Contributions from non-controlling interests (6)	13.0	8.4

(1) See "Item 1. Financial Statements—Note 5" for more information regarding the AR Facility and our related party debt.
(2) ENLC owns all of our outstanding common units, and we make quarterly distributions to ENLC related to its ownership of our common units.
(3) See "Item 1. Financial Statements—Note 6" for information on distributions to holders of the Series B Preferred Units and Series C Preferred Units.
(4) 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.
(5) Earnout payments were made in connection to the consideration paid for the Amarillo Rattler Acquisition and the Central Oklahoma Acquisition, both of which included a contingent component payable beginning in 2024. See "Item 1. Financial Statements—Note 10" for additional information on the earnout payments.
(6) Represents contributions from NGP to the Delaware Basin JV.

Capital Requirements

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

Capital expenditures, net to ENLK (1)	$ 340
Operating expenses associated with the relocation of processing facilities, net to ENLK (2)	9
Contributions to unconsolidated affiliate investments (3)	1
Total	$ 350

(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.

Our primary remaining 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 remaining 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 March 31, 2024.

Total Contractual Cash Obligations. A summary of our total contractual cash obligations as of March 31, 2024 is as follows (in millions):

	Payments Due by Period						
	Total	Remainder 2024	2025	2026	2027	2028	Thereafter
ENLK's senior unsecured notes	$ 2,310.5	$ 97.9	$ 421.6	$ 491.0	$ —		$ 1,300.0
Related party debt (1)(2)	2,148.7	—	—	—	150.0	500.0	1,498.7
AR Facility (2)	147.0	—	147.0	—	—	—	—
Interest payable on fixed long-term debt obligations (2)	2,301.1	174.5	222.1	213.3	189.5	175.4	1,326.3
Acquisition contingent consideration (3)	5.9	—	3.1	2.4	0.4	—	—
Operating lease obligations	114.9	25.6	29.1	16.2	6.6	5.9	31.5
Purchase obligations	9.2	9.2	—	—	—	—	—
Pipeline and trucking capacity and deficiency agreements (4)	909.5	71.1	115.0	101.6	88.3	84.9	448.6
Total contractual obligations	$ 7,946.8	$ 378.3	$ 937.9	$ 824.5	$ 434.8	$ 766.2	$ 4,605.1

(1) Related party debt includes borrowings under the Revolving Credit Facility, the 2028 Notes, the 2029 Notes, and the 2030 Notes.
(2) 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 1. Financial Statements—Note 5" for more information regarding the Revolving Credit Facility and the AR 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 1. Financial Statements—Note 10" for additional information.
(4) 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 the remainder of 2024 are expected to be funded from cash flows generated from our operations.

Indebtedness

AR Facility. As of March 31, 2024, the AR Facility had a borrowing base of $389.1 million and there were $147.0 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.

Related Party Debt. We have a related party debt arrangement with ENLC to fund our operations and growth capital expenditures. The interest we are charged for borrowings made through the related party arrangement is substantially the same as interest charged to ENLC on borrowings from third party lenders. The indebtedness under the Revolving Credit Facility, the 2028 Notes, the 2029 Notes, and the 2030 Notes was incurred by ENLC but is guaranteed by us. Therefore, the covenants in the agreements governing such indebtedness described in "Item 1. Financial Statements—Note 5" affect balances owed by us on the related party debt. As of March 31, 2024, we had $2,148.7 million in outstanding borrowings under the related party debt arrangement, of which $150.0 million was related to the Revolving Credit Facility and $1,998.7 million was related to the 2028 Notes, the 2029 Notes, and the 2030 Notes.

Senior Unsecured Notes. As of March 31, 2024, we had $2.3 billion in aggregate principal amount of outstanding senior unsecured notes maturing from 2024 to 2047, of which $97.9 million matured on April 1, 2024 and is classified as "Current maturities of long-term debt" on the consolidated balance sheet.

See "Item 1. Financial Statements—Note 5" for more information on our outstanding debt.

Inflation

See "Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations—Recent Developments Affecting Industry Conditions and Our Business—Inflation" for more information.

Recent Accounting Pronouncements

We have reviewed recently issued accounting pronouncements that became effective during the three months ended March 31, 2024 and have determined that none had a material impact to our consolidated financial statements.

Disclosure Regarding Forward-Looking Statements

This Quarterly Report 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 Quarterly 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, future transactions with CCS counterparties, 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 and a default under ENLC's Revolving 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) debt levels that 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 Quarterly Report, the risk factors set forth in “Item 1A. Risk Factors” in ENLC’s Annual Report on Form 10-K for the year ended December 31, 2023, 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.