UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

Form 10-Q

☒ **Quarterly Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934**

For the quarterly period ended June 30, 2021

OR

☐ **Transition Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934**

For the transition period from to

Commission file number: 001-36336

ENLINK MIDSTREAM, LLC

(Exact name of registrant as specified in its charter)

Delaware	**46-4108528**
(State of organization)	(I.R.S. Employer Identification No.)
1722 Routh St., Suite 1300 **Dallas, Texas**	**75201**
(Address of principal executive offices)	(Zip Code)

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

SECURITIES REGISTERED PURSUANT TO SECTION 12(b) OF THE SECURITIES EXCHANGE ACT OF 1934:

Title of Each Class	Trading Symbol	Name of Exchange on which Registered
Common Units Representing Limited Liability Company Interests	ENLC	The New York Stock Exchange

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

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

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

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

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

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

As of July 29, 2021, the Registrant had 488,622,133 common units outstanding.

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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 related to our operating segments. 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.
AR Facility	A three-year committed accounts receivable securitization facility of up to $300 million entered into by EnLink Midstream Funding, LLC, a bankruptcy-remote special purpose entity and our indirect subsidiary, with PNC Bank, National Association, as administrative agent and lender, and PNC Capital Markets, LLC, as structuring agent.
ASC	The FASB Accounting Standards Codification.
Ascension JV	Ascension Pipeline Company, LLC, a joint venture between a subsidiary of ENLK and a subsidiary of Marathon Petroleum Corporation in which ENLK owns a 50% interest and Marathon Petroleum Corporation owns a 50% interest. The Ascension JV, which began operations in April 2017, owns an NGL pipeline that connects ENLK's Riverside fractionator to Marathon Petroleum Corporation's Garyville refinery.
Bbls	Barrels.
Bcf	Billion cubic feet.
Cedar Cove JV	Cedar Cove Midstream LLC, a joint venture between a subsidiary of ENLK and a subsidiary of Kinder Morgan, Inc. in which ENLK owns a 30% interest and Kinder Morgan, Inc. owns a 70% interest. The Cedar Cove JV, which was formed in November 2016, owns gathering and compression assets in Blaine County, Oklahoma, located in the STACK play.
CFTC	U.S. Commodity Futures Trading Commission.
CNOW	Central Northern Oklahoma Woodford Shale.
Commission	U.S. Securities and Exchange Commission.
Consolidated Credit Facility	A $1.75 billion unsecured revolving credit facility entered into by ENLC that matures on January 25, 2024, which includes a $500.0 million letter of credit subfacility.
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 plant located in the Delaware Basin in Texas.
Devon	Devon Energy Corporation.
ENLC	EnLink Midstream, LLC.
ENLK	EnLink Midstream Partners, LP or, when applicable, EnLink Midstream Partners, LP together with its consolidated subsidiaries. Also referred to as the "Partnership."
FASB	Financial Accounting Standards Board.
GAAP	Generally accepted accounting principles in the United States of America.
Gal	Gallons.
GCF	Gulf Coast Fractionators, which owns an NGL fractionator in Mont Belvieu, Texas. ENLK owns 38.75% of GCF.
General Partner	EnLink Midstream GP, LLC, the general partner of ENLK.
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.
Managing Member	EnLink Midstream Manager, LLC, the managing member of ENLC.
Merger	On January 25, 2019, NOLA Merger Sub, LLC (previously a wholly-owned subsidiary of ENLC) merged with and into ENLK with ENLK continuing as the surviving entity and a subsidiary of ENLC.
Midland Basin	A large sedimentary basin in West Texas.
MMbbls	Million barrels.
MMbtu	Million British thermal units.
MMcf	Million cubic feet.
MVC	Minimum volume commitment.

NGL	Natural gas liquid.
NGP	NGP Natural Resources XI, LP.
OPEC+	Organization of the Petroleum Exporting Countries and its broader partners.
Operating Partnership	EnLink Midstream Operating, LP, a Delaware limited partnership and wholly owned subsidiary of ENLK.
ORV	ENLK’s Ohio River Valley crude oil, condensate stabilization, natural gas compression, and brine disposal assets in the Utica and Marcellus shales.
OTC	Over-the-counter.
Permian Basin	A large sedimentary basin that includes the Midland and Delaware Basins.
POL contracts	Percentage-of-liquids contracts.
POP contracts	Percentage-of-proceeds contracts.
Series B Preferred Units	ENLK’s Series B Cumulative Convertible Preferred Units.
Series C Preferred Units	ENLK’s Series C Fixed-to-Floating Rate Cumulative Redeemable Perpetual Preferred Units.
STACK	Sooner Trend Anadarko Basin Canadian and Kingfisher Counties in Oklahoma.
Term Loan	A term loan originally in the amount of $850.0 million entered into by ENLK on December 11, 2018 with Bank of America, N.A., as Administrative Agent, Bank of Montreal and Royal Bank of Canada, as Co-Syndication Agents, Citibank, N.A. and Wells Fargo Bank, National Association, as Co-Documentation Agents, and the lenders party thereto, which ENLC assumed in connection with the Merger and the obligations of which ENLK guarantees.

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

	June 30, 2021	December 31, 2020
	(Unaudited)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 32.8	$ 39.6
Accounts receivable:		
Trade, net of allowance for bad debt of $0.3 and $0.5, respectively	55.3	80.6
Accrued revenue and other	534.3	447.5
Fair value of derivative assets	69.1	25.0
Other current assets	116.6	58.7
Total current assets	808.1	651.4
Property and equipment, net of accumulated depreciation of $4,096.8 and $3,863.0, respectively	6,493.6	6,652.1
Intangible assets, net of accumulated amortization of $731.3 and $668.8, respectively	1,120.2	1,125.4
Investment in unconsolidated affiliates	30.7	41.6
Fair value of derivative assets	2.0	4.9
Other assets, net	111.9	75.5
Total assets	$ 8,566.5	$ 8,550.9
LIABILITIES AND MEMBERS' EQUITY		
Current liabilities:		
Accounts payable and drafts payable	$ 95.5	$ 60.5
Accounts payable to related party	1.4	1.0
Accrued gas, NGLs, condensate, and crude oil purchases	415.0	290.5
Fair value of derivative liabilities	107.6	37.1
Current maturities of long-term debt	249.9	349.8
Other current liabilities	170.1	149.1
Total current liabilities	1,039.5	888.0
Long-term debt	4,206.4	4,244.0
Asset retirement obligations	14.6	14.2
Other long-term liabilities	89.3	80.6
Deferred tax liability, net	118.7	108.6
Fair value of derivative liabilities	—	2.5
Members' equity:		
Members' equity (489,854,915 and 489,381,149 units issued and outstanding, respectively)	1,390.1	1,508.8
Accumulated other comprehensive loss	(8.0)	(15.3)
Non-controlling interest	1,715.9	1,719.5
Total members' equity	3,098.0	3,213.0
Commitments and contingencies (Note 15)		
Total liabilities and members' equity	$ 8,566.5	$ 8,550.9

See accompanying notes to consolidated financial statements.

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

	Three Months Ended June 30, 2021	Three Months Ended June 30, 2020	Six Months Ended June 30, 2021	Six Months Ended June 30, 2020
	(Unaudited)			
Revenues:				
Product sales	$ 1,235.6	$ 532.6	$ 2,358.5	$ 1,425.5
Midstream services	209.3	234.7	418.2	478.7
Loss on derivative activity	(38.2)	(22.4)	(121.6)	(3.2)
Total revenues	1,406.7	744.9	2,655.1	1,901.0
Operating costs and expenses:				
Cost of sales, exclusive of operating expenses and depreciation and amortization (1)(2)	1,055.1	397.7	1,989.8	1,153.0
Operating expenses	96.8	88.1	153.1	188.8
Depreciation and amortization	151.9	158.2	302.9	321.0
Impairments	—	1.5	—	354.5
(Gain) loss on disposition of assets	(0.3)	5.2	(0.3)	4.6
General and administrative	26.1	23.5	52.1	53.9
Total operating costs and expenses	1,329.6	674.2	2,497.6	2,075.8
Operating income (loss)	77.1	70.7	157.5	(174.8)
Other income (expense):				
Interest expense, net of interest income	(60.0)	(55.2)	(120.0)	(110.8)
Gain on extinguishment of debt	—	26.7	—	32.0
Income (loss) from unconsolidated affiliates	(1.3)	(0.7)	(7.6)	1.0
Other income	0.2	—	0.1	—
Total other expense	(61.1)	(29.2)	(127.5)	(77.8)
Income (loss) before non-controlling interest and income taxes	16.0	41.5	30.0	(252.6)
Income tax benefit (expense)	(6.6)	(11.7)	(8.0)	22.0
Net income (loss)	9.4	29.8	22.0	(230.6)
Net income attributable to non-controlling interest	31.0	25.7	56.3	52.1
Net income (loss) attributable to ENLC	$ (21.6)	$ 4.1	$ (34.3)	$ (282.7)
Net income (loss) attributable to ENLC per unit:				
Basic common unit	$ (0.04)	$ 0.01	$ (0.07)	$ (0.58)
Diluted common unit	$ (0.04)	$ 0.01	$ (0.07)	$ (0.58)

(1) Includes related party cost of sales of $3.6 million and $1.3 million for the three months ended June 30, 2021 and 2020, respectively, and excludes all operating expenses as well as depreciation and amortization related to our operating segments of $150.1 million and $156.1 million for the three months ended June 30, 2021 and 2020, respectively.
(2) Includes related party cost of sales of $6.8 million and $4.2 million for the six months ended June 30, 2021 and 2020, respectively, and excludes all operating expenses as well as depreciation and amortization related to our operating segments of $299.1 million and $316.9 million for the six months ended June 30, 2021 and 2020, respectively.

See accompanying notes to consolidated financial statements.

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2021	2020	2021	2020
	(Unaudited)			
Net income (loss)	$ 9.4	$ 29.8	$ 22.0	$ (230.6)
Unrealized gain (loss) on designated cash flow hedge (1)	3.7	1.5	7.3	(11.6)
Comprehensive income (loss)	13.1	31.3	29.3	(242.2)
Comprehensive income attributable to non-controlling interest	31.0	25.7	56.3	52.1
Comprehensive income (loss) attributable to ENLC	$ (17.9)	$ 5.6	$ (27.0)	$ (294.3)

(1) Includes a tax expense of $1.1 million and a tax expense of $0.5 million for the three months ended June 30, 2021 and 2020, respectively, and a tax expense of $2.2 million and a tax benefit of $3.5 million for the six months ended June 30, 2021 and 2020, respectively.

See accompanying notes to consolidated financial statements.

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

	Common Units		Accumulated Other Comprehensive Loss	Non-Controlling Interest	Total	Redeemable Non-controlling interest (Temporary Equity)
	$	Units	$	$	$	$
			(Unaudited)			
Balance, December 31, 2020	$ 1,508.8	489.4	$ (15.3)	$ 1,719.5	$ 3,213.0	$ —
Conversion of restricted units for common units, net of units withheld for taxes	(1.2)	0.7	—	—	(1.2)	—
Unit-based compensation	6.5	—	—	—	6.5	—
Contributions from non-controlling interests	—	—	—	0.9	0.9	—
Distributions	(47.1)	—	—	(25.8)	(72.9)	(0.2)
Unrealized gain on designated cash flow hedge (1)	—	—	3.6	—	3.6	—
Fair value adjustment related to redeemable non-controlling interest	(0.1)	—	—	—	(0.1)	0.2
Net income (loss)	(12.7)	—	—	25.3	12.6	—
Balance, March 31, 2021	1,454.2	490.1	(11.7)	1,719.9	3,162.4	—
Conversion of restricted units for common units, net of units withheld for taxes	(0.2)	0.1	—	—	(0.2)	—
Unit-based compensation	6.4	—	—	—	6.4	—
Contributions from non-controlling interests	—	—	—	1.0	1.0	—
Distributions	(46.7)	—	—	(36.0)	(82.7)	—
Unrealized gain on designated cash flow hedge (2)	—	—	3.7	—	3.7	—
Common units repurchased	(2.0)	(0.3)	—	—	(2.0)	—
Net income (loss)	(21.6)	—	—	31.0	9.4	—
Balance, June 30, 2021	$ 1,390.1	489.9	$ (8.0)	$ 1,715.9	$ 3,098.0	$ —

(1) Includes a tax expense of $1.1 million.
(2) Includes a tax expense of $1.1 million.

See accompanying notes to consolidated financial statements.

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

	Common Units		Accumulated Other Comprehensive Loss	Non-Controlling Interest	Total	Redeemable Non-Controlling Interest (Temporary Equity)
	$	Units	$	$	$	$
			(Unaudited)			
Balance, December 31, 2019	$ 2,135.5	487.8	$ (11.0)	$ 1,681.6	$ 3,806.1	$ 5.2
Conversion of restricted units for common units, net of units withheld for taxes	(4.0)	1.3	—	—	(4.0)	—
Unit-based compensation	12.3	—	—	—	12.3	—
Contributions from non-controlling interests	—	—	—	37.1	37.1	—
Distributions	(93.3)	—	—	(24.4)	(117.7)	(0.3)
Unrealized loss on designated cash flow hedge (1)	—	—	(13.1)	—	(13.1)	—
Fair value adjustment related to redeemable non-controlling interest	0.7	—	—	—	0.7	(0.9)
Redemption of non-controlling interest	—	—	—	—	—	(4.0)
Net income (loss)	(286.8)	—	—	26.4	(260.4)	—
Balance, March 31, 2020	1,764.4	489.1	(24.1)	1,720.7	3,461.0	—
Conversion of restricted units for common units, net of units withheld for taxes	(0.3)	0.4	—	—	(0.3)	—
Unit-based compensation	6.8	—	—	—	6.8	—
Contributions from non-controlling interests	—	—	—	13.2	13.2	—
Distributions	(46.5)	—	—	(35.9)	(82.4)	—
Unrealized gain on designated cash flow hedge (2)	—	—	1.5	—	1.5	—
Net income	4.1	—	—	25.7	29.8	—
Balance, June 30, 2020	$ 1,728.5	489.5	$ (22.6)	$ 1,723.7	$ 3,429.6	$ —

(1) Includes a tax benefit of $4.0 million.
(2) Includes a tax expense of $0.5 million.

See accompanying notes to consolidated financial statements.

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

	Six Months Ended June 30, 2021	Six Months Ended June 30, 2020
	(Unaudited)	
Cash flows from operating activities:		
Net income (loss)	$ 22.0	$ (230.6)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Impairments	—	354.5
Depreciation and amortization	302.9	321.0
Utility credits	(43.8)	—
Deferred income tax (benefit) expense	7.9	(22.7)
Non-cash unit-based compensation	12.9	16.2
Amortization of designated cash flow hedge	6.0	—
Payments to terminate interest rate swaps	(1.3)	—
Non-cash loss on derivatives recognized in net income (loss)	34.2	6.0
Gain on extinguishment of debt	—	(32.0)
Amortization of debt issue costs, net discount (premium) of notes	2.5	2.2
Distribution of earnings from unconsolidated affiliates	—	1.2
(Income) loss from unconsolidated affiliates	7.6	(1.0)
Other operating activities	(2.8)	4.1
Changes in assets and liabilities:		
Accounts receivable, accrued revenue, and other	(61.4)	109.8
Natural gas and NGLs inventory, prepaid expenses, and other	(47.8)	9.3
Accounts payable, accrued product purchases, and other accrued liabilities	163.3	(221.2)
Net cash provided by operating activities	402.2	316.8
Cash flows from investing activities:		
Additions to property and equipment	(62.5)	(203.6)
Acquisitions	(55.0)	—
Distribution from unconsolidated affiliates in excess of earnings	3.7	0.8
Other investing activities	1.6	0.8
Net cash used in investing activities	(112.2)	(202.0)
Cash flows from financing activities:		
Proceeds from borrowings	539.5	490.0
Payments on borrowings	(679.5)	(476.0)
Conversion of restricted units, net of units withheld for taxes	(1.4)	(4.3)
Distribution to members	(93.8)	(139.8)
Distributions to non-controlling interests	(62.0)	(60.6)
Contributions by non-controlling interests	1.9	50.3
Common unit repurchases	(2.0)	—
Other financing activities	0.5	0.2
Net cash used in financing activities	(296.8)	(140.2)
Net decrease in cash and cash equivalents	(6.8)	(25.4)
Cash and cash equivalents, beginning of period	39.6	77.4
Cash and cash equivalents, end of period	$ 32.8	$ 52.0
Supplemental disclosures of cash flow information:		
Cash paid for interest	$ 97.1	$ 106.6
Cash paid (refunded) for income taxes	$ 0.2	$ (1.0)
Non-cash investing activities:		
Non-cash accrual of property and equipment	$ 6.9	$ (19.6)
Non-cash acquisitions	$ 16.5	$ —
Right-of-use assets obtained in exchange for operating lease liabilities	$ 10.7	$ 4.8
Non-cash financing activities:		
Redemption of non-controlling interest	$ —	$ (4.0)

See accompanying notes to consolidated financial statements.

ENLINK MIDSTREAM, LLC AND SUBSIDIARIES
Notes to Consolidated Financial Statements
June 30, 2021
(Unaudited)

(1) General

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

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

ENLC is a Delaware limited liability company formed in October 2013. The Company's common units are traded on the New York Stock Exchange under the symbol "ENLC." ENLC owns all of ENLK's common units and also owns all of the membership interests of the General Partner. The General Partner manages ENLK's operations and activities.

b. Nature of Business

We primarily focus on providing midstream energy services, including:

- gathering, compressing, treating, processing, transporting, storing, and selling natural gas;
- fractionating, transporting, storing, and selling NGLs; and
- gathering, transporting, stabilizing, storing, trans-loading, and selling crude oil and condensate, in addition to brine disposal services.

Our midstream energy asset network includes approximately 12,000 miles of pipelines, 23 natural gas processing plants with approximately 5.5 Bcf/d of processing capacity, seven fractionators with approximately 290,000 Bbls/d of fractionation capacity, barge and rail terminals, product storage facilities, purchasing and marketing capabilities, brine disposal wells, a crude oil trucking fleet, and equity investments in certain joint ventures. Our operations are based in the United States, and our sales are derived primarily from domestic customers.

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

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

Our crude oil and condensate business includes the gathering and transmission of crude oil and condensate via pipelines, barges, rail, and trucks, in addition to condensate stabilization and brine disposal. We also purchase crude oil and condensate from producers and other supply sources and sell that crude oil and condensate through our terminal facilities to various markets.

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

c. COVID-19 Update

On March 11, 2020, the World Health Organization declared the ongoing coronavirus (COVID-19) outbreak a pandemic and recommended containment and mitigation measures worldwide. There is considerable uncertainty regarding how long the COVID-19 pandemic will persist and affect economic conditions and the extent and duration of changes in consumer behavior.

(2) Significant Accounting Policies

a. Basis of Presentation

The accompanying consolidated financial statements have been prepared in accordance with the instructions to Form 10-Q, 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 on Form 10-K for the year ended December 31, 2020. Certain reclassifications were made to the financial statements for the prior period to conform to current period presentation. The effect of these reclassifications had no impact on previously reported members' equity or net income (loss). All significant intercompany balances and transactions have been eliminated in consolidation.

b. Revenue Recognition

The following table summarizes the contractually committed fees that we expect to recognize in our consolidated statements of operations, in either revenue or reductions to cost of sales, from MVC and firm transportation contractual provisions. All amounts in the table below are determined using the contractually-stated MVC or firm transportation volumes specified for each period multiplied by the relevant deficiency or reservation fee. Actual amounts could differ due to the timing of revenue recognition or reductions to cost of sales resulting from make-up right provisions included in our agreements, as well as due to nonpayment or nonperformance by our customers. We record revenue under MVC contracts during periods of shortfall when it is known that the customer cannot, or will not, make up the deficiency. These fees do not represent the shortfall amounts we expect to collect under our MVC contracts, as we generally do not expect volume shortfalls to equal the full amount of the contractual MVCs during these periods. For example, for the three and six months ended June 30, 2021, we had contractual commitments of $10.9 million and $24.4 million under our MVC contracts, respectively, and recorded $0.3 million of revenue due to volume shortfalls for the six months ended June 30, 2021.No revenue due to volume shortfalls was recorded for the three months ended June 30, 2021.

MVC and Firm Transportation Commitments (in millions) (1)	
2021 (remaining)	$ 75.1
2022	134.1
2023	121.6
2024	105.8
2025	62.2
Thereafter	342.1
Total	$ 840.9

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

c. Acquisition of Business

On April 30, 2021, we completed the acquisition of Amarillo Rattler, LLC, the owner of a gathering and processing system located in the Midland Basin. In connection with the purchase, we entered into an amended and restated gas gathering and processing agreement with Diamondback Energy, strengthening our dedicated acreage position with Diamondback Energy. We acquired the system with an upfront payment of $50.0 million, which was paid with cash-on-hand, with an additional $10 million to be paid on April 30, 2022, and contingent consideration capped at $15 million based on Diamondback Energy's drilling activity above historical levels.

Under the acquisition method of accounting, the acquired assets of Amarillo Rattler, LLC have been recorded at their respective fair values as of the date of the acquisition. We have prepared a preliminary purchase price allocation, which is subject to change upon finalization. Determining the fair value of the assets of Amarillo Ratter, LLC requires judgment and certain assumptions to be made, particularly related to the valuation of acquired customer relationships. The inputs and assumptions related to the customer relationships are categorized as level 3 in the fair value hierarchy. On a historical pro forma basis, our consolidated revenues, net income (loss), total assets, and earnings per unit amounts would not have differed materially had the acquisition been completed on January 1, 2021 rather than April 30, 2021.

(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 following table represents our change in carrying value of intangible assets (in millions):

	Gross Carrying Amount	Accumulated Amortization	Net Carrying Amount
Six Months Ended June 30, 2021			
Customer relationships, beginning of period	$ 1,794.2	$ (668.8)	$ 1,125.4
Customer relationships obtained from acquisition of business	57.3	—	57.3
Amortization expense	—	(62.5)	(62.5)
Customer relationships, end of period	$ 1,851.5	$ (731.3)	$ 1,120.2

The weighted average amortization period for intangible assets is 14.9 years. Amortization expense was $31.6 million and $30.9 million for the three months ended June 30, 2021 and 2020, respectively, and $62.5 million and $61.8 million for the six months ended June 30, 2021 and 2020, respectively.

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

2021 (remaining)	$ 64.1
2022	128.2
2023	128.2
2024	128.2
2025	110.8
Thereafter	560.7
Total	$ 1,120.2

(4) Related Party Transactions

Transactions with Cedar Cove JV. For the three and six months ended June 30, 2021, we recorded cost of sales of $3.6 million and $6.8 million, respectively, and for the three and six months ended June 30, 2020, we recorded costs of sales of $1.3 million and $4.2 million, respectively, related to our purchase of residue gas and NGLs from the Cedar Cove JV subsequent to processing at our Central Oklahoma processing facilities. Additionally, we had accounts payable balances related to transactions with the Cedar Cove JV of $1.4 million and $1.0 million at June 30, 2021 and December 31, 2020, respectively.

Transactions with GIP. For the three and six months ended June 30, 2021, we recorded general and administrative expenses of $0.1 million and $0.2 million, respectively, related to personnel secondment services provided by GIP. We did not record any expenses related to transactions with GIP for the three and six months ended June 30, 2020.

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

(5) Long-Term Debt

As of June 30, 2021 and December 31, 2020, long-term debt consisted of the following (in millions):

	June 30, 2021			December 31, 2020		
	Outstanding Principal	Premium (Discount)	Long-Term Debt	Outstanding Principal	Premium (Discount)	Long-Term Debt
Term Loan due 2021 (1)	$ 250.0	$ —	$ 250.0	$ 350.0	$ —	$ 350.0
AR Facility due 2023 (2)	210.0	—	210.0	250.0	—	250.0
Consolidated Credit Facility due 2024	—	—	—	—	—	—
ENLK’s 4.40% Senior unsecured notes due 2024	521.8	0.9	522.7	521.8	1.1	522.9
ENLK’s 4.15% Senior unsecured notes due 2025	720.8	(0.5)	720.3	720.8	(0.6)	720.2
ENLK’s 4.85% Senior unsecured notes due 2026	491.0	(0.3)	490.7	491.0	(0.4)	490.6
ENLC's 5.625% Senior unsecured notes due 2028	500.0	—	500.0	500.0	—	500.0
ENLC’s 5.375% Senior unsecured notes due 2029	498.7	—	498.7	498.7	—	498.7
ENLK’s 5.60% Senior unsecured notes due 2044	350.0	(0.2)	349.8	350.0	(0.2)	349.8
ENLK’s 5.05% Senior unsecured notes due 2045	450.0	(5.6)	444.4	450.0	(5.7)	444.3
ENLK’s 5.45% Senior unsecured notes due 2047	500.0	(0.1)	499.9	500.0	(0.1)	499.9
Debt classified as long-term	$ 4,492.3	$ (5.8)	4,486.5	$ 4,632.3	$ (5.9)	4,626.4
Debt issuance cost (3)			(30.2)			(32.6)
Less: Current maturities of long-term debt (1)			(249.9)			(349.8)
Long-term debt, net of unamortized issuance cost			$ 4,206.4			$ 4,244.0

(1) Bears interest based on Prime and/or LIBOR plus an applicable margin. The effective interest rate was 1.6% and 1.7% at June 30, 2021 and December 31, 2020, respectively. The Term Loan will mature on December 10, 2021. Therefore, the outstanding principal balance, net of discount and debt issuance costs, is classified as “Current maturities of long-term debt” on the consolidated balance sheet as of June 30, 2021 and December 31, 2020, respectively.
(2) Bears interest based on LMIR and/or LIBOR plus an applicable margin. The effective interest rate was 1.3% and 2.0% at June 30, 2021 and December 31, 2020, respectively.
(3) Net of amortization of $16.4 million and $14.1 million at June 30, 2021 and December 31, 2020, respectively.

Term Loan

On December 11, 2018, ENLK entered into the Term Loan with Bank of America, N.A., as Administrative Agent, Bank of Montreal and Royal Bank of Canada, as Co-Syndication Agents, Citibank, N.A. and Wells Fargo Bank, National Association, as Co-Documentation Agents, and the lenders party thereto. Upon the closing of the Merger, ENLC assumed ENLK’s obligations under the Term Loan, and ENLK became a guarantor of the Term Loan. In the event that ENLC defaults on the Term Loan and the outstanding balance becomes due, ENLK will be liable for any amount owed on the Term Loan not paid by

ENLC. In May 2021, we repaid $100.0 million of the borrowings under the Term Loan due December 2021. The outstanding balance of the Term Loan was $250.0 million as of June 30, 2021. The obligations under the Term Loan are unsecured.

Under the terms of the Term Loan, if we consummate one or more acquisitions in which the aggregate purchase price is $50.0 million or more, we can elect to increase the maximum allowed ratio of consolidated indebtedness to consolidated EBITDA to 5.5 to 1.0 for the quarter in which the acquisition occurs and the three subsequent quarters. In April 2021, we completed the acquisition of Amarillo Rattler, LLC with an aggregate purchase price in excess of $50.0 million and elected to increase the maximum allowed ratio of consolidated indebtedness to consolidated EBITDA to 5.5 to 1.0 through its maturity date. At June 30, 2021, we were in compliance with and expect to be in compliance with the financial covenants of the Term Loan until the Term Loan matures on December 10, 2021.

AR Facility

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

On February 26, 2021, the SPV entered into an amendment to the AR Facility that, among other things: (i) increased the AR Facility limit and lender commitments by $50.0 million to $300.0 million, (ii) reduced the Adjusted LIBOR and LMIR (each as defined in the AR Facility) minimum floor to zero, rather than the previous 0.375%, and (iii) reduced the currently effective drawn fee to 1.25% rather than the previous 1.625%.

Since our investment in the SPV is not sufficient to finance its activities without additional support from us, the SPV is a variable interest entity. We are the primary beneficiary of the SPV because we have the power to direct the activities that most significantly affect its economic performance and we are obligated to absorb its losses or receive its benefits from operations. Since we are the primary beneficiary of the SPV, we consolidate its assets and liabilities, which consist primarily of billed and unbilled accounts receivable of $566.9 million and long-term debt of $210.0 million as of June 30, 2021.

The amount available for borrowings at any one time under the AR Facility is limited to a borrowing base amount calculated based on the outstanding balance of eligible receivables held as collateral, subject to certain reserves, concentration limits, and other limitations. As of June 30, 2021, the AR Facility had a borrowing base of $300.0 million. Borrowings under the AR Facility bear interest (based on LIBOR or LMIR (as defined in the AR Facility)) plus a drawn fee in the amount of 1.25% at June 30, 2021. The drawn fee varies based on ENLC's credit rating, and the SPV also pays a fee on the undrawn committed amount of the AR Facility. Interest and fees payable by the SPV under the AR Facility are due monthly.

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

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

At June 30, 2021, we were in compliance with and expect to be in compliance with the financial covenants of the AR Facility for at least the next twelve months.

Consolidated Credit Facility

The Consolidated Credit Facility permits ENLC to borrow up to $1.75 billion on a revolving credit basis and includes a $500.0 million letter of credit subfacility. The Consolidated Credit Facility became available for borrowings and letters of credit upon closing of the Merger. In addition, ENLK became a guarantor under the Consolidated Credit Facility upon the closing of the Merger. In the event that ENLC's obligations under the Consolidated Credit Facility are accelerated due to a default, ENLK will be liable for the entire outstanding balance and 105% of the outstanding letters of credit under the Consolidated Credit Facility. There were no outstanding borrowings under the Consolidated Credit Facility and $40.7 million outstanding letters of credit as of June 30, 2021.

Under the terms of the Consolidated Credit Facility, if we consummate one or more acquisitions in which the aggregate purchase price is $50.0 million or more, we can elect to increase the maximum allowed ratio of consolidated indebtedness to consolidated EBITDA to 5.5 to 1.0 for the quarter in which the acquisition occurs and the three subsequent quarters. In April 2021, we completed the acquisition of Amarillo Rattler, LLC with an aggregate purchase price in excess of $50.0 million and elected to increase the maximum allowed ratio of consolidated indebtedness to consolidated EBITDA to 5.5 to 1.0 through the first quarter of 2022. At June 30, 2021, we were in compliance with and expect to be in compliance with the financial covenants of the Consolidated Credit Facility for at least the next twelve months.

(6) Income Taxes

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2021	2020	2021	2020
Current income tax expense	$ —	$ (0.4)	$ (0.1)	$ (0.7)
Deferred income tax benefit (expense)	(6.6)	(11.3)	(7.9)	22.7
Income tax benefit (expense)	$ (6.6)	$ (11.7)	$ (8.0)	$ 22.0

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2021	2020	2021	2020
Expected income tax benefit (expense) based on federal statutory rate	$ 3.8	$ (3.7)	$ 6.2	$ 63.6
State income tax benefit (expense), net of federal benefit	0.6	(1.0)	0.8	7.0
Unit-based compensation (1)	(0.4)	(6.8)	(2.9)	(4.4)
Non-deductible expense related to goodwill impairment	—	—	—	(43.4)
Change in valuation allowance	(1.0)	—	(2.2)	—
Oklahoma statutory rate change (2)	(7.6)	—	(7.6)	—
Other	(2.0)	(0.2)	(2.3)	(0.8)
Income tax benefit (expense)	$ (6.6)	$ (11.7)	$ (8.0)	$ 22.0

(1) Related to book-to-tax differences recorded upon the vesting of restricted incentive units.
(2) Oklahoma House Bill 2960 resulted in a change in the corporate income tax rate from 6% to 4%, effective January 1, 2022. Accordingly, we recorded deferred tax expense in the amount of $7.6 million for the three and six months ended June 30, 2021 due to a remeasurement of deferred tax assets.

Deferred Tax Assets and Liabilities

Deferred income taxes reflect the net tax effects of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for income tax purposes. The deferred tax liabilities, net of deferred tax assets, are included in "Deferred tax liability, net" in the consolidated balance sheets. As of June 30, 2021, we had $118.7 million of deferred tax liabilities, net of $439.6 million of deferred tax assets, which included a $155.5 million valuation allowance. As of December 31, 2020, we had $108.6 million of deferred tax liabilities, net of $396.0 million of deferred tax assets, which included a $153.3 million valuation allowance.

A valuation allowance is established to reduce deferred tax assets if all, or some portion, of such assets will more than likely not be realized. We established a valuation allowance of $153.3 million as of December 31, 2020, primarily related to federal and state tax operating loss carryforwards for which we do not believe a tax benefit is more likely than not to be realized. For the three and six months ended June 30, 2021, we recorded a $1.0 million and $2.2 million valuation allowance adjustment, respectively. As of June 30, 2021, management believes it is more likely than not that the Company will realize the benefits of the deferred tax assets, net of valuation allowance.

(7) Certain Provisions of the ENLK Partnership Agreement

a. Series B Preferred Units

As of June 30, 2021 and December 31, 2020, there were60,499,149 and 60,197,784 Series B Preferred Units issued and outstanding, respectively.

A summary of the distribution activity relating to the Series B Preferred Units during the six months ended June 30, 2021 and 2020 is provided below:

Declaration period	Distribution paid as additional Series B Preferred Units	Cash Distribution (in millions)		Date paid/payable
2021				
Fourth Quarter of 2020	150,494	$	16.9	February 12, 2021
First Quarter of 2021	150,871	$	17.0	May 14, 2021
Second Quarter of 2021	151,248	$	17.0	August 13, 2021
2020				
Fourth Quarter of 2019	148,999	$	16.8	February 13, 2020
First Quarter of 2020	149,371	$	16.8	May 13, 2020
Second Quarter of 2020	149,745	$	16.8	August 13, 2020

b. Series C Preferred Units

As of June 30, 2021 and December 31, 2020, there were400,000 Series C Preferred Units issued and outstanding, respectively. ENLK distributed $12.0 million to holders of Series C Preferred Units during the three and six months ended June 30, 2021 and 2020, respectively.

(8) Members' Equity

a. Common Unit Repurchase Program

In November 2020, the board of directors of the Managing Member authorized a common unit repurchase program for the repurchase of up to $100.0 million of outstanding ENLC common units and reauthorized such program in April 2021. The repurchases will be made, in accordance with applicable securities laws, from time to time in open market or private transactions and may be made pursuant to a trading plan meeting the requirements of Rule 10b5-1 under the Securities Exchange Act of 1934, as amended (the "Exchange Act"). The repurchases will depend on market conditions and may be discontinued at any time.

For the three and six months ended June 30, 2021, ENLC repurchased317,751 outstanding ENLC common units for an aggregate cost, including commissions, of $2.0 million, or an average of $6.22 per common unit.

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b. Earnings Per Unit and Dilution Computations

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2021	2020	2021	2020
Distributed earnings allocated to:				
Common units (1)	$ 46.0	$ 45.9	$ 91.9	$ 91.7
Unvested restricted units (1)	1.1	0.8	2.2	1.6
Total distributed earnings	$ 47.1	$ 46.7	$ 94.1	$ 93.3
Undistributed loss allocated to:				
Common units	$ (67.1)	$ (42.2)	$ (125.4)	$ (369.6)
Unvested restricted units	(1.6)	(0.4)	(3.0)	(6.4)
Total undistributed loss	$ (68.7)	$ (42.6)	$ (128.4)	$ (376.0)
Net income (loss) attributable to ENLC allocated to:				
Common units	$ (21.1)	$ 3.7	$ (33.5)	$ (277.9)
Unvested restricted units	(0.5)	0.4	(0.8)	(4.8)
Total net income (loss) attributable to ENLC	$ (21.6)	$ 4.1	$ (34.3)	$ (282.7)
Basic and diluted total net income (loss) attributable to ENLC per unit:				
Basic	$ (0.04)	$ 0.01	$ (0.07)	$ (0.58)
Diluted	$ (0.04)	$ 0.01	$ (0.07)	$ (0.58)

(1) Represents distribution activity consistent with the distribution activity described in "*Distributions*" below.

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2021	2020	2021	2020
Basic weighted average units outstanding:				
Weighted average common units outstanding	490.0	489.3	490.0	489.0
Diluted weighted average units outstanding:				
Weighted average basic common units outstanding	490.0	489.3	490.0	489.0
Dilutive effect of non-vested restricted units (1)	—	1.1	—	—
Total weighted average diluted common units outstanding	490.0	490.4	490.0	489.0

(1) All common unit equivalents were antidilutive for the three and six months ended June 30, 2021 and the six months ended June 30, 2020 since a net loss existed for those periods.

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

c. Distributions

A summary of our distribution activity related to the ENLC common units for the six months ended June 30, 2021 and 2020, respectively, is provided below:

Declaration period	Distribution/unit	Date paid/payable
2021		
Fourth Quarter of 2020	$ 0.09375	February 12, 2021
First Quarter of 2021	$ 0.09375	May 14, 2021
Second Quarter of 2021	$ 0.09375	August 13, 2021
2020		
Fourth Quarter of 2019	$ 0.1875	February 13, 2020
First Quarter of 2020	$ 0.09375	May 13, 2020
Second Quarter of 2020	$ 0.09375	August 13, 2020

(9) Investment in Unconsolidated Affiliates

As of June 30, 2021, our unconsolidated investments consisted of a38.75% ownership in GCF and a 30% ownership in the Cedar Cove JV. The following table shows the activity related to our investment in unconsolidated affiliates for the periods indicated (in millions):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2021	2020	2021	2020
GCF				
Distributions	$ —	$ —	$ 3.5	$ 1.6
Equity in income (loss)	$ (0.7)	$ 0.3	$ (6.4)	$ 2.1
Cedar Cove JV				
Distributions	$ 0.1	$ 0.2	$ 0.2	$ 0.4
Equity in loss	$ (0.6)	$ (1.0)	$ (1.2)	$ (1.1)
Total				
Distributions	$ 0.1	$ 0.2	$ 3.7	$ 2.0
Equity in income (loss)	$ (1.3)	$ (0.7)	$ (7.6)	$ 1.0

The following table shows the balances related to our investment in unconsolidated affiliates as of June 30, 2021 and December 31, 2020 (in millions):

	June 30, 2021	December 31, 2020
GCF	$ 30.7	$ 40.6
Cedar Cove JV (1)	(0.4)	1.0
Total investment in unconsolidated affiliates	$ 30.3	$ 41.6

(1) As of June 30, 2021, our investment in the Cedar Cove JV is classified as "Other long-term liabilities" on the consolidated balance sheet.

(10) Employee Incentive Plans

a. Long-Term Incentive Plans

We account for unit-based compensation in accordance with ASC 718,*Compensation—Stock Compensation*, which requires that compensation related to all unit-based awards be recognized in the consolidated financial statements. Unit-based compensation cost is valued at fair value at the date of grant, and that grant date fair value is recognized as expense over each award's requisite service period with a corresponding increase to equity or liability based on the terms of each award and the appropriate accounting treatment under ASC 718. Unit-based compensation associated with ENLC's unit-based compensation plan awarded to directors, officers, and employees of the General Partner is recorded by ENLK since ENLC has no substantial or managed operating activities other than its interests in ENLK.

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2021	2020	2021	2020
Cost of unit-based compensation charged to operating expense	$ 1.7	$ 2.0	$ 3.4	$ 4.2
Cost of unit-based compensation charged to general and administrative expense	4.7	5.4	9.5	12.0
Total unit-based compensation expense	$ 6.4	$ 7.4	$ 12.9	$ 16.2
Amount of related income tax benefit recognized in net income (loss) (1)	$ 1.5	$ 1.7	$ 3.0	$ 3.8

(1) For the three and six months ended June 30, 2021, the amount of related income tax benefit recognized in net income excluded $0.4 million and $2.9 million of income tax expense, respectively, related to book-to-tax differences recorded upon the vesting of restricted units. For the three and six months ended June 30, 2020, the amount of related income tax benefit recognized in net income (loss) excluded $6.8 million and $4.4 million of income tax expense, respectively, related to book-to-tax differences recorded upon the vesting of restricted units.

b. ENLC Restricted Incentive Units

ENLC restricted incentive units were valued at their fair value at the date of grant, which is equal to the market value of ENLC common units on such dateA summary of the restricted incentive unit activity for the six months ended June 30, 2021 is provided below:

	Six Months Ended June 30, 2021	
ENLC Restricted Incentive Units:	**Number of Units**	**Weighted Average Grant-Date Fair Value**
Non-vested, beginning of period	5,350,086	$ 8.45
Granted (1)	3,782,744	3.76
Vested (1)(2)	(970,835)	12.86
Forfeited	(335,539)	6.19
Non-vested, end of period	7,826,456	$ 5.73
Aggregate intrinsic value, end of period (in millions)	$ 50.0	

(1) Restricted incentive units typically vest at the end of three years.
(2) Vested units included 279,970 units withheld for payroll taxes paid on behalf of employees.

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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 and six months ended June 30, 2021 and 2020 is provided below (in millions):

	Three Months Ended June 30,		Six Months Ended June 30,	
ENLC Restricted Incentive Units:	**2021**	**2020**	**2021**	**2020**
Aggregate intrinsic value of units vested	$ 0.9	$ 0.8	$ 3.9	$ 10.9
Fair value of units vested	$ 2.3	$ 6.1	$ 12.5	$ 25.0

As of June 30, 2021, there were $22.4 million of unrecognized compensation costs that related to non-vested ENLC restricted incentive units. These costs are expected to be recognized over a weighted-average period of 1.8 years.

c. ENLC Performance Units

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

The following table presents a summary of the performance units:

	Six Months Ended June 30, 2021	
ENLC Performance Units:	**Number of Units**	**Weighted Average Grant-Date Fair Value**
Non-vested, beginning of period	2,351,241	$ 8.82
Granted	1,388,139	4.70
Vested (1)	(164,553)	26.73
Non-vested, end of period	3,574,827	$ 6.40
Aggregate intrinsic value, end of period (in millions)	$ 22.8	

(1) Vested units included 63,901 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 and six months ended June 30, 2021 and 2020 is provided below (in millions).

	Three Months Ended June 30,		Six Months Ended June 30,	
ENLC Performance Units:	**2021**	**2020**	**2021**	**2020**
Aggregate intrinsic value of units vested	$ —	$ —	$ 0.6	$ 0.9
Fair value of units vested	$ —	$ 0.5	$ 4.4	$ 5.5

As of June 30, 2021, there were $12.6 million of unrecognized compensation costs that related to non-vested ENLC performance units. These costs are expected to be recognized over a weighted-average period of 1.6 years.

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

ENLC Performance Units:	**January 2021**	**July 2020**	**March 2020**	**January 2020**
Grant-Date Fair Value	$ 4.70	$ 2.33	$ 1.13	$ 7.69
Beginning TSR price	$ 3.71	$ 2.52	$ 1.25	$ 6.13
Risk-free interest rate	0.17 %	0.17 %	0.42 %	1.62 %
Volatility factor	71.00 %	67.00 %	51.00 %	37.00 %

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(11) Derivatives

Interest Rate Swaps

In April 2019, we entered into $850.0 million of interest rate swaps to manage the interest rate risk associated with our floating-rate, LIBOR-based borrowings. Under this arrangement, we pay a fixed interest rate of 2.28% in exchange for LIBOR-based variable interest through December 2021. There was no ineffectiveness related to this hedge.

In connection with the partial repayments of the Term Loan in May 2021 and December 2020, we paid $1.3 million to terminate $100.0 million of the interest rate swaps and $10.9 million to terminate $500.0 million of the interest rate swaps, respectively, for an aggregate termination of $600.0 million of the $850.0 million interest rate swaps and settled $1.3 million and $10.9 million, respectively, for an aggregate $12.2 million of the outstanding derivative liability. The unrealized loss remains in accumulated other comprehensive income (loss) and will amortize into “Interest expense” on the consolidated statements of operations until the original maturity date of the Term Loan. For the three and six months ended June 30, 2021, we amortized $3.1 million and $6.0 million, respectively, into interest expense out of accumulated other comprehensive income (loss) related to the termination of the interest rate swaps. The remaining $250.0 million interest rate swaps were re-designated as a cash flow hedge on LIBOR-based borrowings and continue to be effective.

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2021	2020	2021	2020
Change in fair value of interest rate swaps	$ 4.8	$ 2.0	$ 9.5	$ (15.1)
Tax benefit (expense)	(1.1)	(0.5)	(2.2)	3.5
Unrealized gain (loss) on designated cash flow hedge	$ 3.7	$ 1.5	$ 7.3	$ (11.6)

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2021	2020	2021	2020
Interest expense	$ 4.8	$ 3.7	$ 9.6	$ 5.0

We expect to recognize an additional $8.7 million of interest expense out of accumulated other comprehensive loss over the next twelve months.

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

	June 30, 2021	December 31, 2020
Fair value of derivative liabilities—current	$ (2.7)	$ (7.6)

Commodity Swaps

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2021	2020	2021	2020
Change in fair value of derivatives	$ (23.8)	$ (18.8)	$ (31.7)	$ (5.8)
Realized gain (loss) on derivatives	(14.4)	(3.6)	(89.9)	2.6
Loss on derivative activity	$ (38.2)	$ (22.4)	$ (121.6)	$ (3.2)

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

	June 30, 2021	December 31, 2020
Fair value of derivative assets—current	$ 69.1	$ 25.0
Fair value of derivative assets—long-term	2.0	4.9
Fair value of derivative liabilities—current	(104.9)	(29.5)
Fair value of derivative liabilities—long-term	—	(2.5)
Net fair value of commodity swaps	$ (33.8)	$ (2.1)

Set forth below are the summarized notional volumes and fair values of all instruments related to commodity swaps that we held for price risk management purposes and the related physical offsets at June 30, 2021 (in millions). The remaining term of the contracts extend no later than December 2022.

		June 30, 2021		
Commodity	Instruments	Unit	Volume	Net Fair Value
NGL (short contracts)	Swaps	Gallons	(204.2)	$ (49.6)
NGL (long contracts)	Swaps	Gallons	17.0	1.5
Natural gas (short contracts)	Swaps	MMbtu	(13.0)	(6.6)
Natural gas (long contracts)	Swaps	MMbtu	12.0	4.5
Crude and condensate (short contracts)	Swaps	MMbbls	(8.5)	(41.5)
Crude and condensate (long contracts)	Swaps	MMbbls	3.9	57.9
Total fair value of commodity swaps				$ (33.8)

On all transactions where we are exposed to counterparty risk, we analyze the counterparty's financial condition prior to entering into an agreement, establish limits, and monitor the appropriateness of these limits on an ongoing basis. We primarily deal with financial institutions when entering into financial derivatives on commodities. We have entered into Master ISDAs that allow for netting of swap contract receivables and payables in the event of default by either party. If our counterparties failed to perform under existing commodity swap contracts, the maximum loss on our gross receivable position of $71.1 million as of June 30, 2021 would be reduced tozero due to the offsetting of gross fair value payables against gross fair value receivables as allowed by the ISDAs.

(12) Fair Value Measurements

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

	Level 2	
	June 30, 2021	December 31, 2020
Interest rate swaps (1)	$ (2.7)	$ (7.6)
Commodity swaps (2)	$ (33.8)	$ (2.1)

(1) The fair values of the interest rate swaps are estimated based on the difference between expected cash flows calculated at the contracted interest rates and the expected cash flows using observable benchmarks for the variable interest rates.
(2) The fair values of commodity swaps represent the amount at which the instruments could be exchanged in a current arms-length transaction adjusted for our credit risk and/or the counterparty credit risk as required under ASC 820, *Fair Value Measurement.*

Fair Value of Financial Instruments

The estimated fair value of our financial instruments has been determined using available market information and valuation methodologies. Considerable judgment is required to develop the estimates of fair value; thus, the estimates provided below are not necessarily indicative of the amount we could realize upon the sale or refinancing of such financial instruments (in millions):

	June 30, 2021		December 31, 2020	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Long-term debt (1)	$ 4,456.3	$ 4,457.7	$ 4,593.8	$ 4,318.2

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(1) The carrying value of long-term debt includes current maturities and is reduced by debt issuance costs of $30.2 million and $32.6 million as of June 30, 2021 and December 31, 2020, respectively. The respective fair values do not factor in debt issuance costs.

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

The fair values of all senior unsecured notes as of June 30, 2021 and December 31, 2020 were based on Level 2 inputs from third-party market quotations.

(13) Segment Information

Starting in the first quarter of 2021, we began evaluating the financial performance of our segments by including realized and unrealized gains and losses resulting from commodity swaps activity in the Permian, Louisiana, Oklahoma, and North Texas segments. Commodity swaps activity was previously reported in the Corporate segment. We have recast segment information for all presented periods prior to the first quarter of 2021 to conform to current period presentation. Identification of the majority of our operating segments is based principally upon geographic regions served:

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

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

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

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

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

ENLINK MIDSTREAM, LLC AND SUBSIDIARIES
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(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. 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 June 30, 2021						
Natural gas sales	$ 97.4	$ 122.0	$ 45.6	$ 26.2	$ —	$ 291.2
NGL sales	0.5	706.6	0.4	(0.1)	—	707.4
Crude oil and condensate sales	170.4	50.9	15.7	—	—	237.0
Product sales	268.3	879.5	61.7	26.1	—	1,235.6
NGL sales—related parties	195.5	30.2	137.1	94.3	(457.1)	—
Crude oil and condensate sales—related parties	—	—	0.1	2.1	(2.2)	—
Product sales—related parties	195.5	30.2	137.2	96.4	(459.3)	—
Gathering and transportation	11.8	16.4	45.9	38.2	—	112.3
Processing	6.0	0.5	28.1	27.0	—	61.6
NGL services	—	17.1	—	0.1	—	17.2
Crude services	4.0	9.6	3.4	0.2	—	17.2
Other services	0.2	0.4	0.2	0.2	—	1.0
Midstream services	22.0	44.0	77.6	65.7	—	209.3
Revenue from contracts with customers	485.8	953.7	276.5	188.2	(459.3)	1,444.9
Cost of sales, exclusive of operating expenses and depreciation and amortization (1)	(402.3)	(838.9)	(164.9)	(108.3)	459.3	(1,055.1)
Realized loss on derivatives	(4.2)	(6.4)	(2.9)	(0.9)	—	(14.4)
Change in fair value of derivatives	(7.9)	(9.4)	(5.3)	(1.2)	—	(23.8)
Adjusted gross margin	71.4	99.0	103.4	77.8	—	351.6
Operating expenses	(27.4)	(31.7)	(17.8)	(19.9)	—	(96.8)
Segment profit	44.0	67.3	85.6	57.9	—	254.8
Depreciation and amortization	(34.6)	(36.1)	(50.6)	(28.8)	(1.8)	(151.9)
Gain on disposition of assets	—	0.2	—	0.1	—	0.3
General and administrative	—	—	—	—	(26.1)	(26.1)
Interest expense, net of interest income	—	—	—	—	(60.0)	(60.0)
Loss from unconsolidated affiliates	—	—	—	—	(1.3)	(1.3)
Other income	—	—	—	—	0.2	0.2
Income (loss) before non-controlling interest and income taxes	$ 9.4	$ 31.4	$ 35.0	$ 29.2	$ (89.0)	$ 16.0
Capital expenditures	$ 39.5	$ 2.2	$ 4.9	$ 1.9	$ 0.1	$ 48.6

(1) Includes related party cost of sales of $3.6 million for the three months ended June 30, 2021 and excludes all operating expenses as well as depreciation and amortization related to our operating segments of $150.1 million for the three months ended June 30, 2021.

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

	Permian	Louisiana	Oklahoma	North Texas	Corporate	Totals
Three Months Ended June 30, 2020						
Natural gas sales	$ 32.4	$ 68.6	$ 28.8	$ 14.6	$ —	$ 144.4
NGL sales	(0.1)	280.9	0.5	—	—	281.3
Crude oil and condensate sales	87.0	14.9	5.0	—	—	106.9
Product sales	119.3	364.4	34.3	14.6	—	532.6
NGL sales—related parties	59.5	3.2	56.0	13.9	(132.5)	0.1
Crude oil and condensate sales—related parties	—	—	0.1	0.4	(0.6)	(0.1)
Product sales—related parties	59.5	3.2	56.1	14.3	(133.1)	—
Gathering and transportation	13.1	11.5	52.5	44.2	—	121.3
Processing	7.5	0.6	32.1	33.0	—	73.2
NGL services	—	18.6	—	0.1	—	18.7
Crude services	5.0	11.0	4.6	—	—	20.6
Other services	0.2	0.4	0.1	0.2	—	0.9
Midstream services	25.8	42.1	89.3	77.5	—	234.7
Crude services—related parties	—	—	0.1	—	(0.1)	—
Midstream services—related parties	—	—	0.1	—	(0.1)	—
Revenue from contracts with customers	204.6	409.7	179.8	106.4	(133.2)	767.3
Cost of sales, exclusive of operating expenses and depreciation and amortization (1)	(138.4)	(312.5)	(61.1)	(18.9)	133.2	(397.7)
Realized gain (loss) on derivatives	(1.1)	(1.8)	(0.8)	0.1	—	(3.6)
Change in fair value of derivatives	(8.0)	(4.1)	(5.9)	(0.8)	—	(18.8)
Adjusted gross margin	57.1	91.3	112.0	86.8	—	347.2
Operating expenses	(22.7)	(27.5)	(19.4)	(18.5)	—	(88.1)
Segment profit	34.4	63.8	92.6	68.3	—	259.1
Depreciation and amortization	(31.0)	(34.6)	(54.1)	(36.4)	(2.1)	(158.2)
Impairments	—	(1.5)	—	—	—	(1.5)
Gain (loss) on disposition of assets	(5.3)	0.1	(0.1)	0.1	—	(5.2)
General and administrative	—	—	—	—	(23.5)	(23.5)
Interest expense, net of interest income	—	—	—	—	(55.2)	(55.2)
Gain on extinguishment of debt	—	—	—	—	26.7	26.7
Loss from unconsolidated affiliates	—	—	—	—	(0.7)	(0.7)
Income (loss) before non-controlling interest and income taxes	$ (1.9)	$ 27.8	$ 38.4	$ 32.0	$ (54.8)	$ 41.5
Capital expenditures	$ 46.9	$ 15.6	$ 3.0	$ 3.0	$ 0.7	$ 69.2

(1) Includes related party cost of sales of $1.3 million for the three months ended June 30, 2020 and excludes all operating expenses as well as depreciation and amortization related to our operating segments of $156.1 million for the three months ended June 30, 2020.

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

	Permian	Louisiana	Oklahoma	North Texas	Corporate	Totals
Six Months Ended June 30, 2021						
Natural gas sales	$ 222.4	$ 243.2	$ 81.5	$ 77.2	$ —	$ 624.3
NGL sales	0.5	1,332.6	1.0	1.1	—	1,335.2
Crude oil and condensate sales	277.7	92.0	29.3	—	—	399.0
Product sales	500.6	1,667.8	111.8	78.3	—	2,358.5
NGL sales—related parties	360.4	53.8	250.2	175.2	(839.6)	—
Crude oil and condensate sales—related parties	—	—	0.1	3.6	(3.7)	—
Product sales—related parties	360.4	53.8	250.3	178.8	(843.3)	—
Gathering and transportation	21.5	32.2	97.2	78.6	—	229.5
Processing	14.2	1.0	44.0	54.1	—	113.3
NGL services	—	39.1	—	0.2	—	39.3
Crude services	7.5	19.5	6.7	0.4	—	34.1
Other services	0.4	0.9	0.4	0.3	—	2.0
Midstream services	43.6	92.7	148.3	133.6	—	418.2
Crude services—related parties	—	—	0.1	—	(0.1)	—
Other services—related parties	—	2.3	—	—	(2.3)	—
Midstream services—related parties	—	2.3	0.1	—	(2.4)	—
Revenue from contracts with customers	904.6	1,816.6	510.5	390.7	(845.7)	2,776.7
Cost of sales, exclusive of operating expenses and depreciation and amortization (1)	(727.9)	(1,579.3)	(315.9)	(212.4)	845.7	(1,989.8)
Realized loss on derivatives	(61.1)	(17.1)	(8.9)	(2.8)	—	(89.9)
Change in fair value of derivatives	(13.2)	(9.8)	(7.1)	(1.6)	—	(31.7)
Adjusted gross margin	102.4	210.4	178.6	173.9	—	665.3
Operating expenses	(15.6)	(60.9)	(37.5)	(39.1)	—	(153.1)
Segment profit	86.8	149.5	141.1	134.8	—	512.2
Depreciation and amortization	(68.1)	(72.2)	(101.3)	(57.5)	(3.8)	(302.9)
Gain on disposition of assets	0.1	0.1	—	0.1	—	0.3
General and administrative	—	—	—	—	(52.1)	(52.1)
Interest expense, net of interest income	—	—	—	—	(120.0)	(120.0)
Loss from unconsolidated affiliates	—	—	—	—	(7.6)	(7.6)
Other income	—	—	—	—	0.1	0.1
Income (loss) before non-controlling interest and income taxes	$ 18.8	$ 77.4	$ 39.8	$ 77.4	$ (183.4)	$ 30.0
Capital expenditures	$ 52.8	$ 5.0	$ 6.8	$ 4.3	$ 0.5	$ 69.4

(1) Includes related party cost of sales of $6.8 million for the six months ended June 30, 2021 and excludes all operating expenses as well as depreciation and amortization related to our operating segments of $299.1 million for the six months ended June 30, 2021.

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

	Permian	Louisiana	Oklahoma	North Texas	Corporate	Totals
Six Months Ended June 30, 2020						
Natural gas sales	$ 47.5	$ 150.2	$ 69.9	$ 34.7	$ —	$ 302.3
NGL sales	0.1	654.6	1.7	0.3	—	656.7
Crude oil and condensate sales	372.0	73.3	21.2	—	—	466.5
Product sales	419.6	878.1	92.8	35.0	—	1,425.5
NGL sales—related parties	105.4	10.0	123.6	31.1	(270.1)	—
Crude oil and condensate sales—related parties	0.1	—	(0.1)	1.9	(1.9)	—
Product sales—related parties	105.5	10.0	123.5	33.0	(272.0)	—
Gathering and transportation	29.4	23.2	108.8	90.1	—	251.5
Processing	11.8	1.3	65.4	68.4	—	146.9
NGL services	—	38.2	—	0.1	—	38.3
Crude services	9.2	21.6	8.9	—	—	39.7
Other services	0.8	0.8	0.2	0.5	—	2.3
Midstream services	51.2	85.1	183.3	159.1	—	478.7
Crude services—related parties	—	—	0.2	—	(0.2)	—
Midstream services—related parties	—	—	0.2	—	(0.2)	—
Revenue from contracts with customers	576.3	973.2	399.8	227.1	(272.2)	1,904.2
Cost of sales, exclusive of operating expenses and depreciation and amortization (1)	(452.3)	(772.2)	(154.8)	(45.9)	272.2	(1,153.0)
Realized gain (loss) on derivatives	(0.2)	2.5	—	0.3	—	2.6
Change in fair value of derivatives	1.4	(5.1)	(2.1)	—	—	(5.8)
Adjusted gross margin	125.2	198.4	242.9	181.5	—	748.0
Operating expenses	(48.2)	(59.3)	(42.3)	(39.0)	—	(188.8)
Segment profit	77.0	139.1	200.6	142.5	—	559.2
Depreciation and amortization	(60.2)	(72.4)	(110.7)	(73.6)	(4.1)	(321.0)
Impairments	(184.6)	(169.9)	—	—	—	(354.5)
Gain (loss) on disposition of assets	(4.9)	0.1	0.1	0.1	—	(4.6)
General and administrative	—	—	—	—	(53.9)	(53.9)
Interest expense, net of interest income	—	—	—	—	(110.8)	(110.8)
Gain on extinguishment of debt	—	—	—	—	32.0	32.0
Loss from unconsolidated affiliates	—	—	—	—	1.0	1.0
Income (loss) before non-controlling interest and income taxes	$ (172.7)	$ (103.1)	$ 90.0	$ 69.0	$ (135.8)	$ (252.6)
Capital expenditures	$ 132.9	$ 30.8	$ 11.5	$ 7.7	$ 1.1	$ 184.0

(1) Includes related party cost of sales of $4.2 million for the six months ended June 30, 2020 and excludes all operating expenses as well as depreciation and amortization related to our operating segments of $316.9 million for the six months ended June 30, 2020.

ENLINK MIDSTREAM, LLC AND SUBSIDIARIES
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The table below represents information about segment assets as of June 30, 2021 and December 31, 2020 (in millions):

Segment Identifiable Assets:	June 30, 2021	December 31, 2020
Permian	$ 2,387.5	$ 2,236.3
Louisiana	2,349.2	2,312.4
Oklahoma	2,698.8	2,847.6
North Texas	960.9	1,008.6
Corporate (1)	170.1	146.0
Total identifiable assets	$ 8,566.5	$ 8,550.9

(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.

(14) 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:	June 30, 2021	December 31, 2020
Natural gas and NGLs inventory	$ 76.5	$ 44.9
Prepaid expenses and other	40.1	13.8
Other current assets	$ 116.6	$ 58.7

Other current liabilities:	June 30, 2021	December 31, 2020
Accrued interest	$ 49.7	$ 35.7
Accrued wages and benefits, including taxes	18.2	22.5
Accrued ad valorem taxes	22.8	26.5
Capital expenditure accruals	17.3	10.6
Short-term lease liability	17.3	16.3
Operating expense accruals	11.7	8.4
Other	33.1	29.1
Other current liabilities	$ 170.1	$ 149.1

(15) 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 several pending customer billing disputes, including one that has resulted in litigation, and we could be involved in other disputes and litigation arising out of the storm in the future.

We are involved in various litigation and administrative proceedings arising in the normal course of business. We cannot currently predict the outcome of these contingencies and therefore have not accrued any costs associated with potential claims. In the opinion of management, any liabilities that may result from such claims would not individually or in aggregate have a material adverse effect on our financial position, results of operations, or cash flows.

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

Overview

ENLC is a Delaware limited liability company formed in October 2013. ENLC's material assets consist of all of the outstanding common units of ENLK and all of the membership interests of the General Partner. All of our midstream energy assets are owned and operated by ENLK and its subsidiaries. We primarily focus on providing midstream energy services, including:

- gathering, compressing, treating, processing, transporting, storing, and selling natural gas;
- fractionating, transporting, storing, and selling NGLs; and
- gathering, transporting, stabilizing, storing, trans-loading, and selling crude oil and condensate, in addition to brine disposal services.

Our midstream energy asset network includes approximately 12,000 miles of pipelines, 23 natural gas processing plants with approximately 5.5 Bcf/d of processing capacity, seven fractionators with approximately 290,000 Bbls/d of fractionation capacity, barge and rail terminals, product storage facilities, purchasing and marketing capabilities, brine disposal wells, a crude oil trucking fleet, and equity investments in certain joint ventures. We manage and report our activities primarily according to the nature of activity and geography.

Starting in the first quarter of 2021, we began evaluating the financial performance of our segments by including realized and unrealized gains and losses resulting from commodity swaps activity in the Permian, Louisiana, Oklahoma, and North Texas segments. Commodity swaps activity was previously reported in the Corporate segment. We have recast segment information for all presented periods prior to the first quarter of 2021 to conform to current period presentation. Identification of the majority of our operating segments is based principally upon geographic regions served:

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

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

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

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

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

We manage our consolidated operations by focusing on adjusted gross margin because our business is generally to gather, process, transport, or market natural gas, NGLs, crude oil, and condensate using our assets for a fee. We earn our fees through various fee-based contractual arrangements, which include stated fee-only contract arrangements or arrangements with fee-based components where we purchase and resell commodities in connection with providing the related service and earn a net margin as our fee. We earn our net margin under our purchase and resell contract arrangements primarily as a result of stated service-related fees that are deducted from the price of the commodity purchase. While our transactions vary in form, the essential element of most of our transactions is the use of our assets to transport a product or provide a processed product to an end-user or marketer at the tailgate of the plant, pipeline, or barge, truck, or rail terminal. Adjusted gross margin is a non-GAAP financial measure and is explained in greater detail under "Non-GAAP Financial Measures" below. Approximately 87% of our adjusted gross margin was derived from fee-based contractual arrangements with minimal direct commodity price exposure for the six months ended June 30, 2021.

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

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

The following customers represent a significant percentage of revenues, and the loss of the customer would have a material adverse impact on our results of operations because the revenues and adjusted gross margin received from transactions with these customers is material to us.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2021	2020	2021	2020
Devon	7.6 %	17.7 %	7.3 %	15.0 %
Dow Hydrocarbons and Resources LLC	15.2 %	13.5 %	14.9 %	12.3 %
Marathon Petroleum Corporation	12.8 %	10.3 %	13.8 %	14.8 %

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

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

We gather or transport crude oil and condensate owned by others by rail, truck, pipeline, and barge facilities under fee-only contract arrangements based on volumes gathered or transported. We also buy crude oil and condensate on our own gathering systems, third-party systems, and trucked from producers at a market index less a stated transportation deduction. We then transport and resell the crude oil and condensate through a process of basis and fixed price trades. We execute substantially all purchases and sales concurrently, thereby establishing the net margin we will receive for each crude oil and condensate transaction.

We realize adjusted gross margins from our gathering and processing services primarily through different contractual arrangements: processing margin ("margin") contracts, POL contracts, POP contracts, fixed-fee based contracts, or a combination of these contractual arrangements. See “Item 3. Quantitative and Qualitative Disclosures about Market Risk—Commodity Price Risk” for a detailed description of these contractual arrangements. Under any of these gathering and processing arrangements, we may earn a fee for the services performed, or we may buy and resell the gas and/or NGLs as part of the processing arrangement and realize a net margin as our fee. Under margin contract arrangements, our adjusted gross margins are higher during periods of high NGL prices relative to natural gas prices. Adjusted gross margin results under POL contracts are impacted only by the value of the liquids produced with margins higher during periods of higher liquids prices. Adjusted gross margin results under POP contracts are impacted only by the value of the natural gas and liquids produced with margins higher during periods of higher natural gas and liquids prices. Under fixed-fee based contracts, our adjusted gross margins are driven by throughput volume.

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

Recent Developments Affecting Industry Conditions and Our Business

Current Market Environment

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

Production levels by our exploration and production customers are driven in large part by the level of oil and natural gas prices. New drilling activity is necessary to maintain or increase production levels as oil and natural gas wells experience production declines over time. New drilling activity generally moves in the same direction as crude oil and natural gas prices as those prices drive investment returns and cash flow available for reinvestment by exploration and production companies. Accordingly, our 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.

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. During 2020, the COVID-19 pandemic and related travel and operational restrictions, as well as business closures and curtailed consumer activity, led to a reduction in global demand for energy, volatility in the market prices for crude oil, condensate, natural gas, and NGLs, and a significant reduction in the market price of crude oil during the first half of 2020. Although commodity markets have in large part recovered, oil and natural gas commodity prices remain somewhat weak relative to historical levels and continue to remain volatile.

Capital markets and the demands of public investors also affect producer behavior, production levels, and our business. Over the last several years, public investors have exerted pressure on oil and natural gas producers to increase capital discipline and focus on higher investment returns even if it means lower growth. In addition, the ability of companies in the oil and gas industry to access the capital markets on favorable terms has been somewhat negatively impacted. This demand by investors for increased capital discipline from energy companies, as well as the difficulties in accessing capital markets, has led to more modest capital investment by producers, curtailed drilling and production activity, and, accordingly, slower growth for us and other midstream companies during the past few years. This trend was amplified in 2020 as a result of the COVID-19 pandemic demand destruction. Although volumes have now generally recovered to pre-pandemic levels, global capital investments by oil and natural gas producers remain at low levels compared to historical levels and producers 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. As a result of this concentration of drilling activity in the Permian, other basins, including those in which we operate in Oklahoma and North Texas, have experienced reduced incremental new investment and declines in volumes produced. In contrast, we continue to experience an increase in volumes in our Permian segment as our operations in that basin are in a favorable position relative to producer activity.

Our Louisiana segment, while subject to commodity prices and capital markets developments, is less dependent on gathering and processing activities and more affected by industrial demand for the natural gas and NGLs that we supply. Industrial demand along the Gulf Coast region has remained strong from the second half of 2020 and through the first half of 2021, supported by regional industrial activity and export markets. Our activities and, in turn, our financial performance in the Louisiana segment are highly dependent on the availability of natural gas and NGLs produced by our upstream gathering and processing business and by other market participants. To date, the supply of natural gas and NGLs has remained at levels sufficient for us to supply our customers, and maintaining such supply is a key business focus.

For additional discussion regarding these factors, see “Item 1A—Risk Factors—Business and Industry Risks” in our Annual Report on Form 10-K filed with the Commission on February 17, 2021.

Winter Storm Uri

In February 2021, the areas in which we operate experienced a severe winter storm, with extreme cold, ice, and snow occurring over an unprecedented period of approximately 10 days (“Winter Storm Uri”). Winter Storm Uri adversely affected the Company’s facilities and activities across the Company’s footprint, as it did for producers and other midstream companies located in these areas. The severe cold temperatures caused production freeze-offs and also led some producers to proactively shut-in their wells to preserve well integrity. As a result, the Company’s gathering and processing volumes were significantly reduced during this period, with peak volume declines ranging between 44% and 92%, depending on the region. The Company responded to the challenges presented by the storm by taking active steps to ensure the resiliency of the Company’s assets and the protection of the health and well-being of its employees. The Company’s operations and its gathering and processing volumes returned to normal levels by the end of the first quarter of 2021.

The lack of gathered and processed volumes during Winter Storm Uri presented a number of commercial challenges, including the management of losses on derivative contracts and firm commodity sales contracts and making outlays to meet one-time operating expenses for storm recovery. To balance these challenges, the Company was able to use its integrated asset base to make limited incremental gas available to support local markets and to use its storage volumes in Louisiana to help offset lower natural gas and NGL supplies. Additionally, because of idled operations and elevated power prices, the Company was able to earn approximately $49 million in utility credits for unused electricity which had been purchased on a firm basis. These utility credits can be used to offset future power payments. However, because of the magnitude and unprecedented nature of the storm, we cannot predict the full impact that Winter Storm Uri may have on our future results of operations. The ultimate impacts will depend on future developments, including, among other factors, the outcome of pending billing disputes with customers and regulatory actions by state legislatures and other entities responsible for the regulation and pricing of electricity and the electrical grid.

COVID-19 Update

On March 11, 2020, the World Health Organization declared the ongoing coronavirus (COVID-19) outbreak a pandemic and recommended containment and mitigation measures worldwide. Since the outbreak began, our first priority has been the health and safety of our employees and those of our customers and other business counterparties. Beginning in March 2020, we implemented preventative measures and developed a response plan to minimize unnecessary risk of exposure and prevent infection, while supporting our customers’ operations, and we continue to follow these plans. We also continue to promote heightened awareness and vigilance, hygiene, and implementation of more stringent cleaning protocols across our facilities and operations and we continue to evaluate and adjust our preventative measures, response plans, and business practices with the evolving impacts of COVID-19. We have continued to maintain these COVID protocols since the inception of the pandemic and to date we have not experienced any COVID-19 related operational disruptions.

There is considerable uncertainty regarding how long the COVID-19 pandemic will persist and affect economic conditions and the extent and duration of changes in consumer behavior.

We cannot predict the full impact that the COVID-19 pandemic or the volatility in oil and natural gas markets related to COVID-19 will have on our business, liquidity, financial condition, results of operations, and cash flows (including our ability to make distributions to unitholders) at this time due to numerous uncertainties. The ultimate impacts will depend on future developments, including, among others, the ultimate duration and persistence of the pandemic, the speed at which the population is vaccinated against the virus and the efficacy of the vaccines, the impact of the emergence of any new variants of the virus against which vaccines are less effective, the effect of the pandemic on economic, social, and other aspects of everyday life, the consequences of governmental and other measures designed to prevent the spread of the virus, actions taken by members of OPEC+ and other foreign, oil-exporting countries, actions taken by governmental authorities, customers, suppliers, and other third parties, and the timing and extent to which normal economic, social, and operating conditions resume. A sustained significant decline in oil and natural gas exploration and production activities and related reduced demand for our services by our customers, whether due to decreases in consumer demand or reduction in the prices for crude oil, condensate, natural gas, and NGLs or otherwise, would have a material adverse effect on our business, liquidity, financial condition, results of operations, and cash flows (including our ability to make distributions to our unitholders).

For additional discussion regarding risks associated with the COVID-19 pandemic, see "Item 1A—Risk Factors—The ongoing coronavirus (COVID-19) pandemic has adversely affected and could continue to adversely affect our business, financial condition, and results of operations" in our Annual Report on Form 10-K filed with the Commission on February 17, 2021.

Regulatory Developments

On January 20, 2021, the Biden Administration came into office and immediately issued a number of executive orders related to climate change and the production of oil and gas that could affect our operations and those of our customers. On his first day in office, President Biden signed an instrument reentering the United States into the Paris Agreement, effective February 19, 2021, and issued an executive order on "Protecting Public Health and the Environment and Restoring Science to Tackle the Climate Crisis" seeking to adopt new regulations and policies to address climate change and suspend, revise, or rescind prior agency actions that are identified as conflicting with the Biden Administration's climate policies. In addition, on January 27, 2021, President Biden issued an executive order indefinitely suspending new oil and natural gas leases on public lands or in offshore waters pending completion of an ongoing comprehensive review and reconsideration of federal oil and gas permitting and leasing practices, and on April 22, 2021, at a global summit on climate change, President Biden committed the United States to target emissions reductions of 50-52% of 2005 levels by 2030. Lastly, on June 30, 2021, President Biden signed into law a reinstatement of regulations put in place during the Obama administration regarding methane emissions. The Company had previously complied with these regulations during the Obama administration and does not expect the reinstatement to have a material effect on the Company or its operations. The Biden Administration could also seek, in the future, to put into place additional executive orders, policy and regulatory reviews, or seek to have Congress pass legislation that could adversely affect the production of oil and gas assets and our operations and those of our customers.

Only a small percentage of our operations are derived from customers operating on public land, mainly in the Delaware Basin, and these activities are expected to represent only approximately 4% of our total segment profit, net to EnLink, during 2021. In addition, we have a robust program to monitor and prevent methane emissions in our operations and we maintain a comprehensive environmental program that is embedded in our operations. However, our activities that take place on public lands require that we and our producer customers obtain leases, permits, and other approvals from the federal government. While the status of recent and future rules and rulemaking initiatives under the Biden Administration remain uncertain, the regulations that might result from such initiatives, could lead to increased costs for us or our customers, difficulties in obtaining leases, permits, and other approvals for us and our customers, reduced utilization of our gathering, processing and pipeline systems or reduced rates under renegotiated transportation or storage agreements in affected regions. These impacts could, in turn, adversely affect our business, financial condition, results of operations or cash flows, including our ability to make cash distributions to our unitholders.

For more information, see our risk factors under "Environmental, Legal Compliance, and Regulatory Risk" in Section 1A "Risk Factors" in our Annual Report on Form 10-K filed with the Commission on February 17, 2021.

Other Recent Developments

Common Unit Repurchase Program. In November 2020, the board of directors of the Managing Member authorized a common unit repurchase program for the repurchase of up to $100.0 million of outstanding ENLC common units and reauthorized such program in April 2021. The repurchases will be made, in accordance with applicable securities laws, from time to time in open market or private transactions and may be made pursuant to a trading plan meeting the requirements of Rule 10b5-1 under the Exchange Act. The repurchases will depend on market conditions and may be discontinued at any time. For the three and six months ended June 30, 2021, ENLC repurchased 317,751 outstanding ENLC common units for an aggregate cost, including commissions, of $2.0 million, or an average of $6.22 per common unit.

Amarillo Rattler Acquisition. On April 30, 2021, we completed the acquisition of Amarillo Rattler, LLC, the owner of a gathering and processing system located in the Midland Basin. In connection with the purchase, we entered into an amended and restated gas gathering and processing agreement with Diamondback Energy, strengthening our dedicated acreage position with Diamondback Energy. We acquired the system with an upfront payment of $50.0 million, which was paid with cash-on-hand, with an additional $10 million to be paid on April 30, 2022, and contingent consideration capped at $15 million based on Diamondback Energy's drilling activity above historical levels.

War Horse Processing Plant. In December 2020, we began moving equipment and facilities previously associated with the Battle Ridge processing plant in Central Oklahoma to the Permian Basin. This processing plant relocation is expected to increase the processing capacity of our Permian Basin processing facilities by approximately 95 MMcf/d. We expect to complete the relocation in the second half of 2021.

Non-GAAP Financial Measures

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

Adjusted Gross Margin

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

The following table reconciles total revenues and gross margin to adjusted gross margin (in millions):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2021	2020	2021	2020
Total revenues	$ 1,406.7	$ 744.9	$ 2,655.1	$ 1,901.0
Cost of sales, exclusive of operating expenses and depreciation and amortization (1)	(1,055.1)	(397.7)	(1,989.8)	(1,153.0)
Operating expenses	(96.8)	(88.1)	(153.1)	(188.8)
Depreciation and amortization	(151.9)	(158.2)	(302.9)	(321.0)
Gross margin	102.9	100.9	209.3	238.2
Operating expenses	96.8	88.1	153.1	188.8
Depreciation and amortization	151.9	158.2	302.9	321.0
Adjusted gross margin	$ 351.6	$ 347.2	$ 665.3	$ 748.0

(1) Excludes all operating expenses as well as depreciation and amortization related to our operating segments of $150.1 million and $156.1 million for the three months ended June 30, 2021 and 2020, respectively, and $299.1 million and $316.9 million for the six months ended June 30, 2021 and 2020, respectively.

Adjusted EBITDA

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

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

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

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

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2021	2020	2021	2020
Net income (loss)	$ 9.4	$ 29.8	$ 22.0	$ (230.6)
Interest expense, net of interest income	60.0	55.2	120.0	110.8
Depreciation and amortization	151.9	158.2	302.9	321.0
Impairments	—	1.5	—	354.5
(Income) loss from unconsolidated affiliates	1.3	0.7	7.6	(1.0)
Distributions from unconsolidated affiliates	0.1	0.2	3.7	2.0
(Gain) loss on disposition of assets	(0.3)	5.2	(0.3)	4.6
Gain on extinguishment of debt	—	(26.7)	—	(32.0)
Unit-based compensation	6.4	7.4	12.9	16.2
Income tax expense (benefit)	6.6	11.7	8.0	(22.0)
Unrealized loss on commodity swaps	23.8	18.8	31.7	5.8
Relocation costs associated with the War Horse processing facility (1)	10.2	—	17.8	—
Other (2)	0.4	(0.4)	—	(0.5)
Adjusted EBITDA before non-controlling interest	269.8	261.6	526.3	528.8
Non-controlling interest share of adjusted EBITDA from joint ventures (3)	(12.3)	(6.5)	(19.4)	(13.7)
Adjusted EBITDA, net to ENLC	$ 257.5	$ 255.1	$ 506.9	$ 515.1

(1) Represents cost incurred related to the relocation of equipment and facilities from the Battle Ridge processing plant, in the Oklahoma segment, to the Permian segment that we expect to complete in 2021 and are not part of our ongoing operations.
(2) Includes accretion expense associated with asset retirement obligations; transaction costs, and non-cash rent, which relates to lease incentives pro-rated over the lease term.
(3) Non-controlling interest share of adjusted EBITDA from joint ventures includes NGP's 49.9% share of adjusted EBITDA from the Delaware Basin JV, Marathon Petroleum Corporation's 50% share of adjusted EBITDA from the Ascension JV, and other minor non-controlling interests.

Free Cash Flow After Distributions

We define free cash flow after distributions as adjusted EBITDA, net to ENLC, plus (less) (growth capital expenditures, excluding capital expenditures that were contributed by other entities and relate to the non-controlling interest share of our consolidated entities); (maintenance capital expenditures, excluding capital expenditures that were contributed by other entities and relate to the non-controlling interest share of our consolidated entities); (interest expense, net of interest income); (distributions declared on common units); (accrued cash distributions on Series B Preferred Units and Series C Preferred Units paid or expected to be paid); (relocation costs associated with the War Horse processing facility); non-cash interest (income)/expense; (payments to terminate interest rate swaps); (current income taxes); and proceeds from the sale of equipment and land.

Free cash flow after distributions is the principal cash flow metric used by the Company in its public reporting. Free cash flow after distributions is one of the metrics used in our short-term incentive program for compensating employees. It is also used as a supplemental liquidity measure by our management and by external users of our financial statements, such as investors, commercial banks, research analysts, and others, to assess the ability of our assets to generate cash sufficient to pay interest costs, pay back our indebtedness, make cash distributions, and make capital expenditures.

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

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

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

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

	Three Months Ended June 30, 2021	Three Months Ended June 30, 2020	Six Months Ended June 30, 2021	Six Months Ended June 30, 2020
Net cash provided by operating activities	$ 176.4	$ 134.8	$ 402.2	$ 316.8
Interest expense (1)	55.6	54.0	111.5	108.7
Utility credits (2)	3.4	—	43.8	—
Payments to terminate interest rate swaps (3)	1.3	—	1.3	—
Accruals for settled commodity swap transactions	(2.6)	(5.2)	(2.5)	(0.2)
Distributions from unconsolidated affiliate investment in excess of earnings	0.1	0.6	3.7	0.8
Relocation costs associated with the War Horse processing facility (4)	10.2	—	17.8	—
Other (5)	1.4	(0.1)	2.6	0.6
Changes in operating assets and liabilities which (provided) used cash:				
Accounts receivable, accrued revenues, inventories, and other	91.7	50.2	109.2	(119.1)
Accounts payable, accrued product purchases, and other accrued liabilities	(67.7)	27.3	(163.3)	221.2
Adjusted EBITDA before non-controlling interest	269.8	261.6	526.3	528.8
Non-controlling interest share of adjusted EBITDA from joint ventures (6)	(12.3)	(6.5)	(19.4)	(13.7)
Adjusted EBITDA, net to ENLC	257.5	255.1	506.9	515.1
Growth capital expenditures, net to ENLC (7)	(40.0)	(50.7)	(55.9)	(133.3)
Maintenance capital expenditures, net to ENLC (7)	(7.5)	(7.7)	(12.2)	(15.9)
Interest expense, net of interest income	(60.0)	(55.2)	(120.0)	(110.8)
Distributions declared on common units	(46.7)	(46.4)	(93.4)	(92.9)
ENLK preferred unit accrued cash distributions (8)	(23.0)	(22.8)	(46.0)	(45.6)
Relocation costs associated with the War Horse processing facility (4)	(10.2)	—	(17.8)	—
Non-cash interest expense	2.4	—	4.6	—
Payments to terminate interest rate swaps (3)	(1.3)	—	(1.3)	—
Other (9)	0.3	—	0.8	0.2
Free cash flow after distributions	$ 71.5	$ 72.3	$ 165.7	$ 116.8

(1) Net of amortization of debt issuance costs and discount and premium, which are included in interest expense but not included in net cash provided by operating activities, and non-cash interest income, which is netted against interest expense but not included in adjusted EBITDA.
(2) Under our utility agreements, we are entitled to a base load of electricity and pay or receive credits, based on market pricing, when we exceed or do not use the base load amounts. Due to Winter Storm Uri, we received credits from our utility providers based on market rates for our unused electricity.
(3) Represents cash paid for the early termination of $100.0 million of our interest rate swaps due to the partial repayment of the Term Loan in May 2021. See "Item 1. Financial Statements—Note 11" for information on the partial termination of our interest rate swaps.
(4) Represents cost incurred related to the relocation of equipment and facilities from the Battle Ridge processing plant, in the Oklahoma segment, to the Permian segment that we expect to complete in 2021 and are not part of our ongoing operations.
(5) Includes current income tax expense; amortization of designated cash flow hedge; transaction costs; and non-cash rent, which relates to lease incentives pro-rated over the lease term.
(6) Non-controlling interest share of adjusted EBITDA from joint ventures includes NGP's 49.9% share of adjusted EBITDA from the Delaware Basin JV, Marathon Petroleum Corporation's 50% share of adjusted EBITDA from the Ascension JV, and other minor non-controlling interests.
(7) Excludes capital expenditures that were contributed by other entities and relate to the non-controlling interest share of our consolidated entities.
(8) Represents the cash distributions earned by the Series B Preferred Units and Series C Preferred Units. See "Item 1. Financial Statements— Note 7" for information on the cash distributions earned by holders of the Series B Preferred Units and Series C Preferred Units. Cash distributions to be paid to holders of the Series B Preferred Units and Series C Preferred Units are not available to common unitholders.
(9) Includes current income tax expense and proceeds from the sale of surplus or unused equipment and land, which occurred in the normal operation of our business.

Results of Operations

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

	Permian	Louisiana	Oklahoma	North Texas	Corporate	Totals
Three Months Ended June 30, 2021						
Gross margin	$ 9.4	$ 31.2	$ 35.0	$ 29.1	$ (1.8)	$ 102.9
Depreciation and amortization	34.6	36.1	50.6	28.8	1.8	151.9
Segment profit	44.0	67.3	85.6	57.9	—	254.8
Operating expenses	27.4	31.7	17.8	19.9	—	96.8
Adjusted gross margin	$ 71.4	$ 99.0	$ 103.4	$ 77.8	$ —	$ 351.6
Three Months Ended June 30, 2020						
Gross margin	$ 3.4	$ 29.2	$ 38.5	$ 31.9	$ (2.1)	$ 100.9
Depreciation and amortization	31.0	34.6	54.1	36.4	2.1	158.2
Segment profit	34.4	63.8	92.6	68.3	—	259.1
Operating expenses	22.7	27.5	19.4	18.5	—	88.1
Adjusted gross margin	$ 57.1	$ 91.3	$ 112.0	$ 86.8	$ —	$ 347.2

	Permian	Louisiana	Oklahoma	North Texas	Corporate	Totals
Six Months Ended June 30, 2021						
Gross margin	$ 18.7	$ 77.3	$ 39.8	$ 77.3	$ (3.8)	$ 209.3
Depreciation and amortization	68.1	72.2	101.3	57.5	3.8	302.9
Segment profit	86.8	149.5	141.1	134.8	—	512.2
Operating expenses	15.6	60.9	37.5	39.1	—	153.1
Adjusted gross margin	$ 102.4	$ 210.4	$ 178.6	$ 173.9	$ —	$ 665.3
Six Months Ended June 30, 2020						
Gross margin	$ 16.8	$ 66.7	$ 89.9	$ 68.9	$ (4.1)	$ 238.2
Depreciation and amortization	60.2	72.4	110.7	73.6	4.1	321.0
Segment profit	77.0	139.1	200.6	142.5	—	559.2
Operating expenses	48.2	59.3	42.3	39.0	—	188.8
Adjusted gross margin	$ 125.2	$ 198.4	$ 242.9	$ 181.5	$ —	$ 748.0

	Three Months Ended June 30,		Six Months Ended June 30,	
	2021	2020	2021	2020
Midstream Volumes:				
Permian Segment				
Gathering and Transportation (MMbtu/d)	1,025,900	871,500	976,000	851,300
Processing (MMbtu/d)	958,400	896,100	917,500	878,900
Crude Oil Handling (Bbls/d)	121,900	112,300	115,100	122,900
Louisiana Segment				
Gathering and Transportation (MMbtu/d)	2,139,300	1,873,600	2,145,300	1,958,400
Crude Oil Handling (Bbls/d)	15,200	15,700	15,100	16,600
NGL Fractionation (Gals/d)	7,729,300	7,344,800	7,419,500	7,764,500
Brine Disposal (Bbls/d)	2,900	1,400	2,200	1,600
Oklahoma Segment				
Gathering and Transportation (MMbtu/d)	1,016,200	1,092,600	977,000	1,156,800
Processing (MMbtu/d)	1,040,000	1,082,100	997,900	1,118,300
Crude Oil Handling (Bbls/d)	23,800	30,000	20,700	33,300
North Texas Segment				
Gathering and Transportation (MMbtu/d)	1,377,400	1,485,900	1,367,200	1,531,800
Processing (MMbtu/d)	627,600	670,600	626,100	685,200

Three Months Ended June 30, 2021 Compared to Three Months Ended June 30, 2020

Gross Margin. Gross margin was $102.9 million for the three months ended June 30, 2021 compared to $100.9 million for the three months ended June 30, 2020, an increase of $2.0 million. The primary contributors to the increase were as follows (in millions):

- *Permian Segment.* Gross margin was $9.4 million for the three months ended June 30, 2021 compared to $3.4 million for the three months ended June 30, 2020, an increase of $6.0 million primarily due to the following:

  - Adjusted gross margin in the Permian segment increased $14.3 million, which was primarily driven by:

    - A $20.0 million increase to adjusted gross margin associated with our Permian gas assets primarily due to higher volumes from existing customers.
    - A $0.1 million decrease in unrealized derivative losses.

    These increases were partially offset by a $3.1 million decrease in realized derivative gains and a $2.7 million decrease in adjusted gross margin associated with our Permian crude assets from higher storage fees earned in April of 2020 resulting from negative crude futures, which was partially offset by higher volumes from existing customers.

  - Operating expenses in the Permian segment increased $4.7 million primarily due to increased construction costs associated with our War Horse processing facility and higher compression expenses due to higher volumes. These increases were partially offset by lower utility costs as a result of $8.1 million of utility credits that we received in the second quarter because our electricity usage was below our contractual base load amounts during Winter Storm Uri, which entitled us to credits based on market rates for our unused electricity. These credits can be used to offset future utility payments.

  - Depreciation and amortization in the Permian segment increased $3.6 million primarily due to new assets placed into service, including the Tiger processing plant in August 2020 and gathering and processing assets associated with the acquisition of Amarillo Rattler, LLC in April 2021.

- *Louisiana Segment.* Gross margin was $31.2 million for the three months ended June 30, 2021 compared to $29.2 million for the three months ended June 30, 2020, an increase of $2.0 million primarily due to the following:

    - Adjusted gross margin in the Louisiana segment increased $7.7 million, resulting from:

        - A $10.4 million increase in adjusted gross margin associated with our Louisiana gas assets, which was primarily due to increased gathering and transportation fees as a result of higher volumes transported in addition to increased storage and hub fees following the acquisition of the Jefferson Island storage facility in December 2020.
        - A $7.5 million increase in adjusted gross margin associated with our Louisiana NGL transmission and fractionation assets, which was primarily due to favorable market prices on NGL sales and higher volumes.

      These increases were partially offset by a $4.6 million and $5.3 million increase in realized and unrealized derivative losses, respectively, due to an increase in commodity prices relative to our hedged prices, and a $0.3 million decrease in adjusted gross margin associated with our ORV crude assets, which was primarily due to lower volumes.

    - Operating expenses in the Louisiana segment increased $4.2 million primarily due to higher utility costs, construction fees and services, and labor and benefits expense.

    - Depreciation and amortization in the Louisiana segment increased $1.5 million primarily due to changes in estimated useful lives of certain non-core assets.

- *Oklahoma Segment.* Gross margin was $35.0 million for the three months ended June 30, 2021 compared to $38.5 million for the three months ended June 30, 2020, a decrease of $3.5 million primarily due to the following:

    - Adjusted gross margin in the Oklahoma segment decreased $8.6 million, resulting from:

        - A $4.8 million decrease in adjusted gross margin associated with our Oklahoma gas assets primarily due to a $15.1 million decrease resulting from the expiration of the MVC provision of a gathering and processing contract at the end of 2020. This decrease was partially offset by an increase in processing prices, despite lower processing volumes.
        - A $2.3 million decrease in adjusted gross margin associated with our Oklahoma crude assets primarily due to lower volumes from our existing customers.
        - A $2.1 million increase in realized derivative losses.

      These decreases were partially offset by a $0.6 million decrease in unrealized derivative losses.

    - Operating expenses in the Oklahoma segment decreased $1.6 million primarily due to reductions in compressor rentals.

    - Depreciation and amortization in the Oklahoma segment decreased $3.5 million primarily due to the relocation of the Battle Ridge processing plant to the War Horse processing facility.

- *North Texas Segment.* Gross margin was $29.1 million for the three months ended June 30, 2021 compared to $31.9 million for the three months ended June 30, 2020, a decrease of $2.8 million primarily due to the following:

    - Adjusted gross margin in the North Texas segment decreased $9.0 million, which was primarily due to $7.6 million of decreased revenues due to lower volumes from our existing customers and $1.0 million and $0.4 million of increased realized and unrealized derivative losses, respectively.

    - Operating expenses in the North Texas segment increased $1.4 million primarily due to increased sales and use taxes and operation and maintenance costs. These increases were partially offset by lower materials and supplies expense and compressor rentals related to the assets in this segment.

    - Depreciation and amortization in the North Texas segment decreased $7.6 million primarily due to a change in the estimated useful lives of certain non-core assets that were fully depreciated at the end of 2020.

- *Corporate Segment.* Gross margin was negative $1.8 million for the three months ended June 30, 2021 compared to negative $2.1 million for the three months ended June 30, 2020. Corporate gross margin consists of depreciation and amortization of corporate assets.

General and Administrative Expenses. General and administrative expenses were $26.1 million for the three months ended June 30, 2021 compared to $23.5 million for the three months ended June 30, 2020, an increase of $2.6 million. The increase was primarily due to transaction and transition costs, which increased $1.2 million primarily due to the Amarillo Rattler, LLC acquisition in April 2021, and labor and benefits costs, which increased $1.3 million.

Interest Expense. Interest expense was $60.0 million for the three months ended June 30, 2021 compared to $55.2 million for the three months ended June 30, 2020, an increase of $4.8 million. Interest expense consisted of the following (in millions):

	Three Months Ended June 30,	
	2021	2020
ENLK and ENLC Senior Notes	$ 50.3	$ 43.3
Term Loan	1.3	4.2
AR Facility	0.8	—
Consolidated Credit Facility	1.4	4.1
Capitalized interest	(0.1)	(1.3)
Amortization of debt issue costs and net discounts (premiums)	1.3	1.2
Interest rate swap - realized	4.8	3.7
Other	0.2	—
Total	$ 60.0	$ 55.2

Gain on Extinguishment of Debt. We recognized a gain on extinguishment of debt of $26.7 million for the three months ended June 30, 2020 due to repurchases of the 2024, 2025, 2026, and 2029 Notes in open market transactions.

Income (Loss) from Unconsolidated Affiliate Investments. Loss from unconsolidated affiliate investments was $1.3 million for the three months ended June 30, 2021 compared to loss of $0.7 million for the three months ended June 30, 2020, a decrease of $0.6 million. The decrease was primarily attributable to a reduction of income of $1.0 million from our GCF investment, as a result of the GCF assets being temporarily idled beginning in January 2021, and was partially offset by a reduction of loss of $0.4 million from our Cedar Cove JV.

Income Tax Benefit (Expense). Income tax expense was $6.6 million for the three months ended June 30, 2021 compared to an income tax expense of $11.7 million for the three months ended June 30, 2020. The decrease in income tax expense was primarily attributable to the decrease in income between periods. See "Item 1. Financial Statements—Note 6" for additional information.

Net Income (Loss) Attributable to Non-Controlling Interest. Net income attributable to non-controlling interest was $31.0 million for the three months ended June 30, 2021 compared to net income of $25.7 million for the three months ended June 30, 2020, an increase of $5.3 million. ENLC's non-controlling interest is comprised of Series B Preferred Units, Series C Preferred Units, NGP's 49.9% share of the Delaware Basin JV, and Marathon Petroleum Corporation's 50% share of the Ascension JV.

Six Months Ended June 30, 2021 Compared to Six Months Ended June 30, 2020

Gross Margin. Gross margin was $209.3 million for the six months ended June 30, 2021 compared to $238.2 million for the six months ended June 30, 2020, a decrease of $28.9 million. The primary contributors to the decrease were as follows (in millions):

- *Permian Segment.* Gross margin was $18.7 million for the six months ended June 30, 2021 compared to $16.8 million for the six months ended June 30, 2020, an increase of $1.9 million primarily due to the following:

    - Adjusted gross margin in the Permian segment decreased $22.8 million, which was primarily driven by:

        - An increase in realized and unrealized derivative losses of $60.9 million and $14.6 million, respectively, due to significant commodity price impacts resulting from Winter Storm Uri and subsequent increases in commodity prices relative to our hedged prices.
        - A $6.7 million decrease to adjusted gross margin associated with our Midland Basin crude assets primarily due to volume declines related to weather disruptions from Winter Storm Uri and due to storage fees earned in April of 2020 due to the negative futures price of crude.

      These decreases were partially offset by a $54.2 million and $3.1 million increase in adjusted gross margin due to higher volumes and due to significant favorable physical commodity prices on sales in our Midland Basin and Delaware gas assets, respectively, resulting from Winter Storm Uri and a $2.1 million increase in adjusted gross margin due to volume growth in our Delaware Basin crude assets from system expansion.

    - Operating expenses in the Permian segment decreased $32.6 million primarily due to lower utility costs as a result of approximately $48.1 million of utility credits that we received because our electricity usage was below our contractual base load amounts during Winter Storm Uri, which entitled us to credits based on market rates for our unused electricity. These credits can be used to offset future utility payments. Operating expenses also decreased due to lower labor expense as a result of reductions in workforce in April 2020. These decreases were partially offset by increases in construction fees and services related to the construction of our War Horse processing facility and higher materials and supplies expense, compressor rentals, and sales and use taxes due to higher volumes.

    - Depreciation and amortization in the Permian segment increased $7.9 million primarily due to new assets placed into service, including the Tiger processing plant in August 2020 and acquisition of the Amarillo Rattler, LLC gathering and processing system in April 2021.

- *Louisiana Segment.* Gross margin was $77.3 million for the six months ended June 30, 2021 compared to $66.7 million for the six months ended June 30, 2020, an increase of $10.6 million primarily due to the following:

    - Adjusted gross margin in the Louisiana segment increased $12.0 million, resulting from:

        - A $29.2 million increase in adjusted gross margin associated with our Louisiana NGL transmission and fractionation assets, which was primarily due to favorable market prices on NGL sales.
        - An $11.8 million increase in adjusted gross margin associated with our Louisiana gas assets, which was primarily due to increased gathering and transportation fees as a result of higher volumes transported and increased storage and hub fees following our acquisition of the Jefferson Island storage facility in December 2020.

      These increases were partially offset by a $19.6 million and $4.7 million increase in realized and unrealized derivative losses, respectively, due to increased commodity prices relative to our hedged prices and a $4.7 million decrease in adjusted gross margin associated with our ORV crude assets, which was primarily due to lower volumes.

    - Operating expenses in the Louisiana segment increased $1.6 million primarily due to increased fees and services, materials and supplies expense, and utilities. This increase was partially offset by lower labor expenses as a result of reductions in workforce in April 2020.

- ◦ Depreciation and amortization in the Louisiana segment decreased $0.2 million primarily due to the impairment of assets in the first quarter of 2020, partially offset by changes in estimated useful lives of certain non-core assets.

- *Oklahoma Segment.* Gross margin was $39.8 million for the six months ended June 30, 2021 compared to $89.9 million for the six months ended June 30, 2020, a decrease of $50.1 million primarily due to the following:

  - ◦ Adjusted gross margin in the Oklahoma segment decreased $64.3 million, resulting from:

    - A $46.5 million decrease in adjusted gross margin associated with our Oklahoma gas assets primarily due to lower volumes from our existing customers, including weather disruptions from Winter Storm Uri, and a $24.9 million decrease due to the expiration of the MVC provision of a gathering and processing contract at the end of 2020.
    - An increase in realized and unrealized derivative losses of $8.9 million and $5.0 million, respectively, due to increased commodity prices relative to our hedged prices.
    - A $3.9 million decrease in adjusted gross margin associated with our Oklahoma crude assets primarily due to lower volumes from our existing customers and partially as a result of weather disruptions from Winter Storm Uri.

  - ◦ Operating expenses in the Oklahoma segment decreased $4.8 million primarily due to reductions in compressor rentals and lower labor and benefits expense as a result of reductions in workforce in April 2020. These decreases were partially offset by higher costs in 2021 to decommission equipment from the Battle Ridge processing plant to be moved to the War Horse processing facility.

  - ◦ Depreciation and amortization in the Oklahoma segment decreased $9.4 million primarily due to the relocation of the Battle Ridge processing plant to the War Horse processing facility.

- *North Texas Segment.* Gross margin was $77.3 million for the six months ended June 30, 2021 compared to $68.9 million for the six months ended June 30, 2020, an increase of $8.4 million primarily due to the following:

  - ◦ Adjusted gross margin in the North Texas segment decreased $7.6 million, which was primarily due to $2.9 million of decreased revenues from volume declines and $3.1 million and $1.6 million of increased realized and unrealized derivative losses, respectively.

  - ◦ Operating expenses in the North Texas segment increased $0.1 million primarily due to increased sales and use taxes and operation and maintenance costs. These increases were partially offset by reductions in compressor rentals, reductions to labor and benefits expense as a result of reductions in workforce in April 2020, and reductions to utility costs.

  - ◦ Depreciation and amortization in the North Texas segment decreased $16.1 million primarily due to a change in the estimated useful lives of certain non-core assets that were fully depreciated at the end of 2020.

- *Corporate Segment.* Gross margin was negative $3.8 million for the six months ended June 30, 2021 compared to negative $4.1 million for the six months ended June 30, 2020. Corporate gross margin consists of depreciation and amortization of corporate assets.

Impairments. For the six months ended June 30, 2021, we did not recognize an impairment expense. For the six months ended June 30, 2020, we recognized impairment expense related to goodwill and property and equipment, including cancelled projects. Impairment expense is composed of the following amounts (in millions):

	Six Months Ended June 30, 2020
Goodwill impairment	$ 184.6
Property and equipment impairment	168.0
Cancelled projects	1.9
Total	$ 354.5

General and Administrative Expenses. General and administrative expenses were $52.1 million for the six months ended June 30, 2021 compared to $53.9 million for the six months ended June 30, 2020, a decrease of $1.8 million. The decrease was primarily due to reduced labor and benefits costs and unit-based compensation costs, which decreased $4.3 million as a result of reductions in workforce in April 2020. This decrease was partially offset by transaction and transition costs, which increased $1.3 million primarily due to the Amarillo Rattler, LLC acquisition in April 2021, and franchise taxes, which increased $0.6 million primarily due to franchise tax refunds in the first half of 2020.

Interest Expense. Interest expense was $120.0 million for the six months ended June 30, 2021 compared to $110.8 million for the six months ended June 30, 2020, an increase of $9.2 million, or 8.3%. Interest expense consisted of the following (in millions):

	Six Months Ended June 30,	
	2021	**2020**
ENLK and ENLC Senior Notes	$ 100.6	$ 87.3
Term Loan	2.7	10.6
AR Facility	2.0	—
Consolidated Credit Facility	2.7	8.2
Capitalized interest	(0.3)	(2.5)
Amortization of debt issue costs and net discounts (premiums)	2.5	2.2
Interest rate swap - realized	9.6	5.0
Other	0.2	—
Total	$ 120.0	$ 110.8

Gain on Extinguishment of Debt. We recognized a gain on extinguishment of debt of $32.0 million for the six months ended June 30, 2020 due to repurchases of the 2024, 2025, 2026, and 2029 Notes in open market transactions.

Income (Loss) from Unconsolidated Affiliate Investments. Loss from unconsolidated affiliate investments was $7.6 million for the six months ended June 30, 2021 compared to income of $1.0 million for the six months ended June 30, 2020, a decrease of $8.6 million. The decrease was primarily attributable to a reduction of income of $8.5 million from our GCF investment, as a result of the GCF assets being temporarily idled beginning in January 2021, and additional losses of $0.1 million from our Cedar Cove JV.

Income Tax Expense. Income tax expense was $8.0 million for the six months ended June 30, 2021 compared to an income tax benefit of $22.0 million for the six months ended June 30, 2020. The decrease in income tax benefit was primarily attributable to the decrease in loss between periods. See “Item 1. Financial Statements—Note 6” for additional information.

Net Income (Loss) Attributable to Non-Controlling Interest. Net income attributable to non-controlling interest was $56.3 million for the six months ended June 30, 2021 compared to net income of $52.1 million for the six months ended June 30, 2020, an increase of $4.2 million. ENLC’s non-controlling interest is comprised of Series B Preferred Units, Series C Preferred Units, NGP’s 49.9% share of the Delaware Basin JV, and Marathon Petroleum Corporation’s 50% share of the Ascension JV.

Critical Accounting Policies

Information regarding our critical accounting policies is included in “Item 7. Management’s Discussion and Analysis of Financial Conditions and Results of Operations” of our Annual Report on Form 10-K for the year ended December 31, 2020.

Liquidity and Capital Resources

Cash Flows from Operating Activities. Net cash provided by operating activities was $402.2 million for the six months ended June 30, 2021 compared to $316.8 million for the six months ended June 30, 2020. Operating cash flows and changes in working capital for comparative periods were as follows (in millions):

	Six Months Ended June 30, 2021	Six Months Ended June 30, 2020
Operating cash flows before working capital	$ 348.1	$ 418.9
Changes in working capital	54.1	(102.1)

Operating cash flows before changes in working capital decreased $70.8 million for the six months ended June 30, 2021 compared to the six months ended June 30, 2020. The primary contributors to the decrease in operating cash flows were as follows:

- Gross margin, excluding depreciation and amortization, non-cash commodity swap activity, utility credits, and unit-based compensation, decreased $63.4 million. For more information regarding the changes in gross margin for the six months ended June 30, 2021 compared to the six months ended June 30, 2020, see “Results of Operations.”

- Interest expense, excluding amortization of debt issue costs and net discounts (premium) of notes, increased $8.9 million.

The changes in working capital for the six months ended June 30, 2021 compared to the six months ended June 30, 2020 were primarily due to fluctuations in trade receivable and payable balances due to timing of collection and payments, changes in inventory balances attributable to normal operating fluctuations, and fluctuations in accrued revenue and accrued cost of sales.

Cash Flows from Investing Activities. Net cash used in investing activities was $112.2 million for the six months ended June 30, 2021 compared to $202.0 million for the six months ended June 30, 2020. Investing cash flows are primarily related to capital expenditures. Capital expenditures decreased from $203.6 million for the six months ended June 30, 2020 to $62.5 million for the six months ended June 30, 2021. The decrease in capital expenditures was primarily due to the completion of major projects in 2020 and was partially offset by $55.0 million related to cash paid for the acquisition of assets for the six months ended June 30, 2021.

Cash Flows from Financing Activities. Net cash used in financing activities was $296.8 million for the six months ended June 30, 2021 compared to $140.2 million for the six months ended June 30, 2020. Our primary financing activities consisted of the following (in millions):

	Six Months Ended June 30,	
	2021	2020
Net repayments on the Term Loan (1)	$ (100.0)	$ —
Net repayments on the AR Facility (1)	(40.0)	—
Net borrowings on the Consolidated Credit Facility (1)	—	50.0
Net repurchases on ENLK's senior unsecured notes (1)	—	(35.2)
Net repurchases on the 2029 Notes (1)	—	(0.8)
Contributions by non-controlling interests (2)	1.9	50.3
Distribution to members	(93.8)	(139.8)
Distributions to Series B Preferred unitholders (3)	(33.9)	(33.6)
Distributions to Series C Preferred unitholders (3)	(12.0)	(12.0)
Distributions to joint venture partners (4)	(16.1)	(15.0)
Common unit repurchases (5)	(2.0)	—

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(1) See "Item 1. Financial Statements—Note 5" for more information regarding the Term Loan, the AR Facility, the Consolidated Credit Facility, and the senior unsecured notes.
(2) Represents contributions from NGP to the Delaware Basin JV.
(3) See "Item 1. Financial Statements—Note 7" 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, distributions to Marathon Petroleum Corporation for its ownership in the Ascension JV, and distributions to other non-controlling interests.
(5) See "Item 1. Financial Statements—Note 8" for more information regarding the ENLC common unit repurchase program.

Capital Requirements. We expect our remaining 2021 capital expenditures, including capital contributions to our unconsolidated affiliate investments, to be approximately $72 million to $102 million, net to ENLC. Our primary capital projects for the remainder of 2021 include continued development of our existing systems through well connects and other low-cost development projects. Additionally, we expect our remaining 2021 operating expenses related to the relocation of equipment and facilities previously associated with the Battle Ridge processing plant in Central Oklahoma to the Permian Basin to be approximately $7 million. These expenses are treated as an operating expense under GAAP and, therefore, are not included in our expected remaining 2021 capital expenditures.

We expect to fund capital expenditures from operating cash flows and capital contributions by joint venture partners that relate to the non-controlling interest share of our consolidated entities. In 2021, it is possible that not all of our planned projects will be commenced or completed. Our ability to pay distributions to our unitholders, to fund planned capital expenditures, and to make acquisitions will depend upon our future operating performance, which will be affected by prevailing economic conditions in the industry, financial, business, and other factors, some of which are beyond our control.

Off-Balance Sheet Arrangements. We had no off-balance sheet arrangements as of June 30, 2021.

Total Contractual Cash Obligations. A summary of our total contractual cash obligations as of June 30, 2021 is as follows (in millions):

	Payments Due by Period						
	Total	Remainder 2021	2022	2023	2024	2025	Thereafter
ENLC's & ENLK's senior unsecured notes	$ 4,032.3	$ —	$ —	$ —	$ 521.8	$ 720.8	$ 2,789.7
Term Loan (1)	250.0	250.0	—	—	—	—	—
AR Facility (2)	210.0	—	—	210.0	—	—	—
Consolidated Credit Facility (3)	—	—	—	—	—	—	—
Acquisition installment payable (4)	10.0	10.0	—	—	—	—	—
Acquisition contingent consideration (5)	6.7	—	—	—	2.2	2.3	2.2
Interest payable on fixed long-term debt obligations	2,436.7	101.7	201.2	201.2	189.7	163.3	1,579.6
Operating lease obligations	118.9	10.7	17.0	11.7	10.2	9.8	59.5
Purchase obligations	4.3	4.3	—	—	—	—	—
Pipeline and trucking capacity and deficiency agreements (6)	187.8	24.3	46.6	38.6	29.2	24.8	24.3
Inactive easement commitment (7)	10.0	—	10.0	—	—	—	—
Total contractual obligations	$ 7,266.7	$ 401.0	$ 274.8	$ 461.5	$ 753.1	$ 921.0	$ 4,455.3

(1) The Term Loan matures on December 10, 2021.
(2) The AR Facility will terminate on October 20, 2023.
(3) The Consolidated Credit Facility will mature on January 25, 2024. As of June 30, 2021, there were no amounts outstanding under the Consolidated Credit Facility.
(4) Amount related to the consideration of the Amarillo Rattler, LLC acquisition due on April 30, 2022.
(5) The estimated fair value of the Amarillo Rattler, LLC contingent consideration was calculated in accordance with the fair value guidance contained in ASC 820, *Fair Value Measurements*. 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.
(6) Consists of pipeline capacity payments for firm transportation and deficiency agreements.
(7) Amount related to inactive easements paid as utilized by us with balance due in 2022 if not utilized.

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

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

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

Indebtedness

In October 2020, we entered into the AR Facility, which is a three-year committed accounts receivable securitization facility originally in the amount of up to $250.0 million. On February 26, 2021, the SPV entered into the First Amendment to the Receivables Financing Agreement, which amended the AR Facility to, among other things, increase the facility limit and lender commitments by $50.0 million to $300.0 million. As of June 30, 2021, the AR Facility had a borrowing base of $300.0 million and there was $210.0 million in outstanding borrowings under the AR Facility.

In addition, as of June 30, 2021, we have $4.0 billion in aggregate principal amount of outstanding unsecured senior notes maturing from 2024 to 2047 and $250.0 million in outstanding principal on the Term Loan. There were no outstanding borrowings under the Consolidated Credit Facility and $40.7 million outstanding letters of credit as of June 30, 2021.

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

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

As of June 30, 2021, ENLC records, on a stand-alone basis, transactions that do not occur at ENLK related to taxation of ENLC, the elimination of intercompany borrowings, and impairment of goodwill that only existed at ENLC.

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

Recent Accounting Pronouncements

See "Item 8. Financial Statements and Supplementary Data—Note 2" in our Annual Report on Form 10-K filed with the Commission on February 17, 2021 for information on recently issued and adopted accounting pronouncements.

Disclosure Regarding Forward-Looking Statements

This Quarterly Report on Form 10-Q 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," "should," "plan," "predict," "anticipate," "intend," "estimate," "expect," "continue," and similar expressions. Such forward-looking statements include, but are not limited to, statements about when additional capacity will be operational, timing for completion of construction or expansion projects, results in certain basins, profitability, financial or leverage metrics, future cost savings or operational initiatives, our future capital structure and credit ratings, objectives, strategies, expectations, and intentions, the impact of the COVID-19 pandemic and Winter Storm Uri on us and our financial results and operations, and other statements that are not historical facts. Factors that could result in such differences or otherwise materially affect our financial condition, results of operation, or cash flows, include, without limitation, (a) the impact of the ongoing coronavirus (COVID-19) pandemic (including the impact of the emergence of any new variants of the virus) on our business, financial condition, and results of operation, (b) potential conflicts of interest of GIP with us and the potential for GIP to favor GIP's own interests to the detriment of our unitholders, (c) GIP's ability to compete with us and the fact that it is not required to offer us the opportunity to acquire additional assets or businesses, (d) a default under GIP's credit facility could result in a change in control of us, could adversely affect the price of our common units, and could result in a default or prepayment event under our credit facility and certain of our other debt, (e) the dependence on Devon for a substantial portion of the natural gas and crude that we gather, process, and transport, (f) developments that materially and adversely affect Devon or other customers, (g) adverse developments in the midstream business that may reduce our ability to make distributions, (h) competition for crude oil, condensate, natural gas, and NGL supplies and any decrease in the availability of such commodities, (i) decreases in the volumes that we gather, process, fractionate, or transport, (j) increasing scrutiny and changing expectations from stakeholders with respect to our environment, social, and governance practices, (k) our ability to receive or renew required permits and other approvals, (l) increased federal, state, and local legislation, and regulatory initiatives, as well as government reviews relating to hydraulic fracturing resulting in increased costs and reductions or delays in natural gas production by our customers, (m) climate change legislation and regulatory initiatives resulting in increased operating costs and reduced demand for the natural gas and NGL services we provide, (n) changes in the availability and cost of capital, including as a result of a change in our credit rating, (o) volatile prices and market demand for crude oil, condensate, natural gas, and NGLs that are beyond our control, (p) our debt levels could limit our flexibility and adversely affect our financial health or limit our flexibility to obtain financing and to pursue other business opportunities, (q) operating hazards, natural disasters, weather-related issues or delays, casualty losses, and other matters beyond our control, (r) reductions in demand for NGL products by the petrochemical, refining, or other industries or by the fuel markets, (s) impairments to goodwill, long-lived assets and equity method investments, and (t) the effects of existing and future laws and governmental regulations, including environmental and climate change requirements and other uncertainties. In addition to the specific uncertainties, factors, and risks discussed above and elsewhere in this Quarterly Report on Form 10-Q and the risk factors set forth in Part I, "Item 1A. Risk Factors" of our Annual Report on Form 10-K for the year ended December 31, 2020 may affect our performance and results of operations. Should one or more of these risks or uncertainties materialize, or should underlying assumptions prove incorrect, actual results may differ materially from those in the forward-looking statements. We disclaim any intention or obligation to update or review any forward-looking statements or information, whether as a result of new information, future events, or otherwise.

Item 3. Quantitative and Qualitative Disclosures about Market Risk

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

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

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

On January 14, 2021, the CFTC published final rules under the Dodd-Frank Act establishing position limit levels for certain energy commodity futures contracts, options and contracts on futures contracts directly or indirectly linked to core referenced futures contracts, and economically equivalent swaps. The position limit levels set the maximum position that a trader may own or control separately or in combination, net long or short, subject to exceptions for certain bona fide hedging transactions. These rules came into effect on March 15, 2021 with compliance dates starting from January 1, 2022.

Commodity Price Risk

We are subject to risks due to fluctuations in commodity prices. Approximately 87% of our adjusted gross margin for the six months ended June 30, 2021 was generated from arrangements with fee-based structures with minimal direct commodity price exposure. Our exposure to these commodity price fluctuations is primarily in the gas processing component of our business. We currently earn adjusted gross margin under four main types of contractual arrangements (or a combination of these types of contractual arrangements) as summarized below.

1. *Fee-based contracts.* Under fee-based contracts, we earn our fees through (1) stated fixed-fee arrangements in which we are paid a fixed fee per unit of volume or (2) arrangements where we purchase and resell commodities in connection with providing the related service and earn a net margin through a fee-like deduction subtracted from the purchase price of the commodities. We may also purchase and resell commodities in arrangements under which we are subject to commodity price fluctuations. Although historically this has not been a material component of our adjusted gross margin, Winter Storm Uri caused sudden and significant price and volume fluctuations that resulted in increased adjusted gross margin that is exposed to commodity price fluctuations. For more information on Winter Storm Uri and its impact on the Company, see the discussion at “Item 2. Management’s Discussion and Analysis of Financial Condition and Results of Operations—Recent Developments Affecting Industry Conditions and Our Business—Winter Storm Uri” in this Report. For the six months ended June 30, 2021, approximately 9% of our adjusted gross margin was generated from purchase and resell arrangements under which we are subject to commodity price fluctuations. This amount was substantially offset by derivative losses.

2. *Processing margin contracts.* Under these contracts, we pay the producer for the full amount of inlet gas to the plant, and we make a margin based on the difference between the value of liquids recovered from the processed natural gas as compared to the value of the natural gas volumes lost and the cost of fuel used in processing. The shrink and fuel losses are referred to as plant thermal reduction, or PTR. Our margins from these contracts are high during periods of

high liquids prices relative to natural gas prices and can be negative during periods of high natural gas prices relative to liquids prices. However, we mitigate our risk of processing natural gas when margins are negative primarily through our ability to bypass processing when it is not profitable for us or by contracts that revert to a minimum fee for processing if the natural gas must be processed to meet pipeline quality specifications. For the six months ended June 30, 2021, less than 1% of our adjusted gross margin was generated from processing margin contracts.

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

4. *POP contracts.* Under these contracts, we receive a fee in the form of a portion of the proceeds of the sale of natural gas and liquids. Therefore, our margins from these contracts are greater during periods of high natural gas and liquids prices. Our margins from processing cannot become negative under POP contracts, but they do decline during periods of low natural gas and liquids prices.

For the six months ended June 30, 2021, approximately 4% of our adjusted gross margin was generated from POL or POP contracts.

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

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

The following table sets forth certain information related to derivative instruments outstanding at June 30, 2021. These derivative instruments mitigate the risks associated with the gas processing and fractionation components of our business. The relevant payment index price for liquids is the monthly average of the daily closing price for deliveries of commodities into Mont Belvieu, Texas as reported by Oil Price Information Service. The relevant index price for natural gas is Henry Hub Gas Daily as defined by the pricing dates in the swap contracts.

Period	Underlying	Notional Volume	We Pay	We Receive (1)	Net Fair Value Asset/(Liability) (In millions)
July 2021 - June 2022	Ethane	1,145 (MBbls)	$0.3160/Gal	Index	$ 0.1
July 2021 - June 2022	Propane	2,510 (MBbls)	Index	$1.0587/Gal	(28.7)
July 2021 - June 2022	Normal butane	698 (MBbls)	Index	$1.2079/Gal	(8.5)
July 2021 - December 2021	Natural gasoline	915 (MBbls)	Index	$1.5912/Gal	(11.0)
July 2021 - March 2022	Natural gas	68,525 (MMbtu/d)	Index	$3.6170/MMbtu	(2.1)
July 2021 - January 2022	Crude and condensate	6,635 (MBbls)	Index	$71.66/Bbl	10.0
July 2021 - December 2022	Crude and condensate	5,792 (MBbls)	$1.813/Bbl	Index (2)	6.4
					$ (33.8)

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

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

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

As of June 30, 2021, outstanding natural gas swap agreements, NGL swap agreements, swing swap agreements, storage swap agreements, and other derivative instruments had a net fair value liability of $33.8 million. The aggregate effect of a hypothetical 10% change, increase or decrease, in gas, crude and condensate, and NGL prices would result in a change of approximately $17.6 million in the net fair value of these contracts as of June 30, 2021.

Interest Rate Risk

We are exposed to interest rate risk on the Term Loan, the AR Facility, and the Consolidated Credit Facility. At June 30, 2021, we had $250.0 million and $210.0 million in outstanding borrowings under the Term Loan and the AR Facility, respectively. At June 30, 2021, we had no outstanding borrowings under the Consolidated Credit Facility.

In April 2019, we entered into $850.0 million of interest rate swaps to reduce the variability of cash outflows associated with interest payments related to our long-term debt with variable interest rates. These swaps were designated as cash flow hedges. In connection with the partial repayments of the Term Loan in May 2021 and December 2020, we terminated $600.0 million of the $850.0 million interest rate swaps. See “Item 1. Financial Statements—Note 11” for more information on our outstanding derivatives.

A 1.0% increase or decrease in interest rates would change our annualized interest expense by approximately $2.5 million and $2.1 million for the Term Loan and the AR Facility, respectively. This change in interest expense would be partially offset by a $2.5 million change related to our open interest rate swap hedge.

We are not exposed to changes in interest rates with respect to ENLK’s senior unsecured notes due in 2024, 2025, 2026, 2044, 2045, or 2047 or our senior unsecured notes due in 2028 and 2029 as these are fixed-rate obligations. As of June 30, 2021, the estimated fair value of the senior unsecured notes was approximately $3,997.7 million, based on the market prices of ENLK’s and our publicly traded debt at June 30, 2021. Market risk is estimated as the potential decrease in fair value of our long-term debt resulting from a hypothetical increase of 1.0% in interest rates. Such an increase in interest rates would result in an approximate $244.9 million decrease in fair value of the senior unsecured notes at June 30, 2021. See “Item 1. Financial Statements—Note 5” for more information on our outstanding indebtedness.

Item 4. Controls and Procedures

a. Evaluation of Disclosure Controls and Procedures

Management of the Managing Member is responsible for establishing and maintaining adequate internal control over financial reporting and for the assessment of the effectiveness of internal control over financial reporting for us. We carried out an evaluation, under the supervision and with the participation of management, including the Chief Executive Officer and Chief Financial Officer of the Managing Member, of the effectiveness of our disclosure controls and procedures as of the end of the period covered by this report pursuant to Exchange Act Rules 13a-15 and 15d-15. Based on that evaluation, the Chief Executive Officer and Chief Financial Officer have concluded that, as of the end of the period covered by this report (June 30, 2021), our disclosure controls and procedures were effective to provide reasonable assurance that information required to be disclosed by us in the reports we file or submit under the Exchange Act is recorded, processed, summarized, and reported within the time period specified in the applicable rules and forms, and that such information is accumulated and communicated to management, including our Chief Executive Officer and Chief Financial Officer, to allow timely decisions regarding disclosure.

b. Changes in Internal Control Over Financial Reporting

There has been no change in our internal control over financial reporting that occurred in the three months ended June 30, 2021 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

PART II—OTHER INFORMATION

Item 1. Legal Proceedings

We are involved in various litigation and administrative proceedings arising in the normal course of business. For a discussion of certain litigation and similar proceedings, please refer to Note 15, "Commitments and Contingencies," of the Notes to Consolidated Financial Statements contained in Part I of this Quarterly Report on Form 10-Q, which is incorporated by reference herein.

Item 1A. Risk Factors

Information about risk factors does not differ materially from that set forth in Part I, "Item 1A. Risk Factors" of our Annual Report on Form 10-K for the year ended December 31, 2020.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds

During the three months ended June 30, 2021, we re-acquired ENLC common units from certain employees in order to satisfy the employees' tax liability in connection with the vesting of restricted incentive units.

Period	Total Number of Units Purchased (1)	Average Price Paid Per Unit	Total Number of Units Purchased as Part of Publicly Announced Plans or Programs (2)	Maximum Dollar Value of Units that May Yet Be Purchased under the Plans or Programs (in millions) (2)
April 1, 2021 to April 30, 2021	227	$ 4.29	—	$ 98.8
May 1, 2021 to May 31, 2021	1,602	4.63	—	$ 98.8
June 1, 2021 to June 30, 2021	355,807	6.16	317,751	$ 96.9
Total	357,636	$ 6.15	317,751	

(1) The total number of units purchased shown in the table includes 39,885 units received by us from employees for the payment of personal income tax withholding on vesting transactions.

(2) On November 4, 2020, we announced a $100.0 million common unit repurchase program. As of June 30, 2021, we repurchased a total of 701,365 common units for an aggregate cost of $3.1 million, or an average of $4.47 per common unit. Future repurchases under the program may be made from time to time in open market or private transactions and may be made pursuant to a trading plan meeting the requirements of Rule 10b5-1 under the Exchange Act. The repurchases will depend on market conditions and may be discontinued at any time.

Item 6. Exhibits

The exhibits filed as part of this report are as follows (exhibits incorporated by reference are set forth with the name of the registrant, the type of report and registration number or last date of the period for which it was filed, and the exhibit number in such filing):

Number		Description
3.1	—	Certificate of Formation of EnLink Midstream, LLC (incorporated by reference to Exhibit 3.1 to our Registration Statement on Form S-4, filed with the Commission on November 20, 2013, file No. 333-192419).
3.2	—	Certificate of Amendment to Certificate of Formation of EnLink Midstream, LLC (incorporated by reference to Exhibit 3.2 to Amendment No. 2 to our Registration Statement on Form S-4, filed with the Commission on January 21, 2014, file No. 333-192419).
3.3	—	Second Amended and Restated Operating Agreement of EnLink Midstream, LLC, dated as of January 25, 2019 (incorporated by reference to Exhibit 3.1 to our Current Report on Form 8-K dated January 25, 2019, filed with the Commission on January 29, 2019, file No. 001-36336).
3.4	—	Certificate of Formation of EnLink Midstream Manager, LLC (incorporated by reference to Exhibit 3.12 to our Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2014, filed with the Commission on August 6, 2014, file No. 001-36336).
3.5	—	Certificate of Amendment to the Certificate of Formation of EnLink Midstream Manager, LLC (incorporated by reference to Exhibit 3.13 to our Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2014, filed with the Commission on August 6, 2014, file No. 001-36336).
3.6	—	Second Amended and Restated Limited Liability Company Agreement of EnLink Midstream Manager, LLC, dated as of July 18, 2018 (incorporated by reference to Exhibit 3.1 to our Current Report on Form 8-K dated July 17, 2018, filed with the Commission on July 23, 2018, file No. 001-36336).
3.7	—	Certificate of Formation of EnLink Midstream GP, LLC (incorporated by reference to Exhibit 3.7 to EnLink Midstream Partners, LP's Registration Statement on Form S-1, file No. 333-97779).
3.8	—	Certificate of Amendment to the Certificate of Formation of EnLink Midstream GP, LLC (incorporated by reference to Exhibit 3.12 to EnLink Midstream Partners, LP's Registration Statement on Form S-3, filed with the Commission on March 10, 2014, file No. 333-194465).
3.9	—	Fourth Amended and Restated Limited Liability Company Agreement of EnLink Midstream GP, LLC, dated as of July 18, 2018 (incorporated by reference to Exhibit 3.2 to our Current Report on Form 8-K dated July 17, 2018, filed with the Commission on July 23, 2018, file No. 001-36366).
3.10	—	Certificate of Limited Partnership of EnLink Midstream Partners, LP (incorporated by reference to Exhibit 3.1 to EnLink Midstream Partners, LP's Registration Statement on Form S-1, filed with the Commission on August 7, 2012, file No. 333-97779).
3.11	—	Certificate of Amendment to the Certificate of Limited Partnership of EnLink Midstream Partners, LP (incorporated by reference to Exhibit 3.2 to EnLink Midstream Partners, LP's Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2012, filed with the Commission on August 7, 2012, file No. 000-50067).
3.12	—	Second Amendment to the Certificate of Limited Partnership of EnLink Midstream Partners, LP (incorporated by reference to Exhibit 3.3 to EnLink Midstream Partners, LP's Current Report on Form 8-K dated March 6, 2014, filed with the Commission on March 11, 2014, file No. 001-36340).
3.13	—	Third Amendment to the Certificate of Limited Partnership of EnLink Midstream Partners, LP (incorporated by reference to Exhibit 3.1 to EnLink Midstream Partners, LP's Current Report on Form 8-K dated June 16, 2017, filed with the Commission on June 19, 2017, file No. 001-36340).
3.14	—	Tenth Amended and Restated Agreement of Limited Partnership of EnLink Midstream Partners, LP, dated as of January 25, 2019 (incorporated by reference to Exhibit 3.2 to our Current Report on Form 8-K dated January 25, 2019, filed with the Commission on January 29, 2019, file No. 001-36336).
4.1 †	—	Indenture, dated as of December 17, 2020, by and among EnLink Midstream, LLC, as issuer, EnLink Midstream Partners, LP, as guarantor, and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.1 to our Current Report on Form 8-K dated December 14, 2020, filed with the Commission on December 18, 2020, file No. 001-36336).
10.1 †	—	Sale and Contribution Agreement, dated as of October 21, 2020, by and among EnLink Midstream Funding, LLC, EnLink Midstream Operating, LP, and the originators from time to time party thereto (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K dated October 21, 2020, filed with the Commission on October 22, 2020, file No. 001-36336).
10.2 †	—	Receivables Financing Agreement, dated as of October 21, 2020, by and among EnLink Midstream Funding, LLC, as borrower, EnLink Midstream Operating, LP, as initial servicer, PNC Bank, National Association, as administrative agent and lender, the lenders party thereto, and PNC Capital Markets, LLC, as structuring agent (incorporated by reference to Exhibit 10.2 to our Current Report on Form 8-K dated October 21, 2020, filed with the Commission on October 22, 2020, file No. 001-36336).
22.1	—	Subsidiary Guarantors (incorporated by reference to Exhibit 22.1 to our Annual Report on Form 10-K dated December 31, 2020, filed with the Commission on February 17, 2021, file No. 001-36336).
31.1 *	—	Certification of the Principal Executive Officer.
31.2 *	—	Certification of the Principal Financial Officer.
32.1 *	—	Certification of the Principal Executive Officer and Principal Financial Officer pursuant to 18 U.S.C. Section 1350.
101 *	—	The following financial information from EnLink Midstream, LLC's Quarterly Report on Form 10-Q for the quarter ended June 30, 2021, formatted in iXBRL (Inline eXtensible Business Reporting Language): (i) Consolidated Balance Sheets as of June 30, 2021 and December 31, 2020, (ii) Consolidated Statements of Operations for the three and six months ended June 30, 2021 and 2020, (iii) Consolidated Statements of Changes in Members' Equity for the three months ended June 30, 2021 and 2020 and March 31, 2021 and 2020, (iv) Consolidated Statements of Cash Flows for the six months ended June 30, 2021 and 2020, and (v) the Notes to Consolidated Financial Statements.
104 *	—	Cover Page Interactive Data File (formatted as Inline iXBRL and included in Exhibit 101).

* Filed herewith.

† As required by 17 CFR § 232.105(d)(2) this exhibit is being provided to correct non-functioning hyperlinks corresponding to exhibits 4.13, 10.21, and 10.22, respectively, in our Annual Report on Form 10-K filed with the Commission on February 17, 2021.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

EnLink Midstream, LLC

By: EnLink Midstream Manager, LLC, its managing member

By: /s/ J. PHILIPP ROSSBACH

J. Philipp Rossbach

Vice President and Chief Accounting Officer

(Principal Accounting Officer)

August 4, 2021

Exhibit 31.1

CERTIFICATIONS

I, Barry E. Davis, certify that:

1. I have reviewed this quarterly report on Form 10-Q of EnLink Midstream, LLC;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: August 4, 2021

/s/ BARRY E. DAVIS

Barry E. Davis
Chairman and Chief Executive Officer
(principal executive officer)

Exhibit 31.2

CERTIFICATIONS

I, Pablo G. Mercado, certify that:

1. I have reviewed this quarterly report on Form 10-Q of EnLink Midstream, LLC;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: August 4, 2021

/s/ PABLO G. MERCADO
Pablo G. Mercado
Executive Vice President and Chief Financial Officer
(principal financial officer)

Exhibit 32.1

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Quarterly Report of EnLink Midstream, LLC (the “Registrant”) on Form 10-Q of the Registrant for the quarter ended June 30, 2021 as filed with the Securities and Exchange Commission on the date hereof (the “Report”), each of the undersigned, Barry E. Davis, Chief Executive Officer of EnLink Midstream Manager, LLC, and Pablo G. Mercado, Chief Financial Officer of EnLink Midstream Manager, LLC, certifies, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to his knowledge:

(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Registrant.

Date: August 4, 2021	/s/ BARRY E. DAVIS Barry E. Davis *Chief Executive Officer*
Date: August 4, 2021	/s/ PABLO G. MERCADO Pablo G. Mercado *Chief Financial Officer*

A signed original of this written statement required by Section 906 has been provided to the Registrant and will be retained by the Registrant and furnished to the Securities and Exchange Commission or its staff upon request. The foregoing certification is being furnished to the Securities and Exchange Commission as an exhibit to the Report.