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 September 30, 2019

OR

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

For the transition period from to

Commission file number: 001-36340

ENLINK MIDSTREAM PARTNERS, LP

(Exact name of registrant as specified in its charter)

Delaware	**16-1616605**
(State of organization)	(I.R.S. Employer Identification No.)
1722 Routh St., Suite 1300 **Dallas, Texas**	**75201**
(Address of principal executive offices)	(Zip Code)

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

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

Title of Each Class	Trading Symbol	Name of Exchange on which Registered
None.	None.	None.

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 November 4, 2019, the Registrant had 144,358,720 common units outstanding, all of which were held by our affiliate, EnLink Midstream, LLC.

TABLE OF CONTENTS

DEFINITIONS

The following terms as defined are used in this document:

Defined Term	Definition
/d	Per day.
2014 Plan	EnLink Midstream, LLC’s 2014 Long-Term Incentive Plan.
AMZ	Alerian MLP Index for Master Limited Partnerships.
ASC	The FASB Accounting Standards Codification.
ASC 842	ASC 842, Leases, a new accounting standard effective January 1, 2019 related to the accounting for lease agreements.
Ascension JV	Ascension Pipeline Company, LLC, a joint venture between a subsidiary of ENLK and a subsidiary of Marathon Petroleum Corporation in which ENLK owns a 50% interest and Marathon Petroleum Corporation owns a 50% interest. The Ascension JV, which began operations in April 2017, owns an NGL pipeline that connects ENLK’s Riverside fractionator to Marathon Petroleum Corporation’s Garyville refinery.
ASU	The FASB Accounting Standards Update.
Avenger	Avenger crude oil gathering system, a crude oil gathering system in the northern Delaware Basin.
Bbls	Barrels.
Bcf	Billion cubic feet.
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. The Consolidated Credit Facility was available upon closing of the Merger and is guaranteed by ENLK.
Delaware Basin JV	Delaware G&P LLC, a joint venture between a subsidiary of ENLK and an affiliate of NGP in which ENLK owns a 50.1% interest and NGP owns a 49.9% interest. The Delaware Basin JV, which was formed in August 2016, owns the Lobo processing facilities located in the Delaware Basin in Texas.
Devon	Devon Energy Corporation.
Enfield	Enfield Holdings, L.P.
ENLC	EnLink Midstream, LLC or, when applicable, EnLink Midstream, LLC together with its consolidated subsidiaries.
ENLC Class C common Units	A class of non-economic ENLC common units issued to Enfield immediately prior to the Merger equal to the number of Series B Preferred Units of ENLK held by Enfield immediately prior to the effective time of the Merger, in order to provide Enfield with certain voting rights with respect to ENLC.
ENLK	EnLink Midstream Partners, LP or, when applicable, EnLink Midstream Partners, LP together with its consolidated subsidiaries. Also referred to as the “Partnership.”
ENLK Credit Facility	A $1.5 billion unsecured revolving credit facility entered into by ENLK that would have matured on March 6, 2020, which included a $500.0 million letter of credit subfacility. The ENLK Credit Facility was terminated on January 25, 2019 in connection with the consummation of the Merger.
EOGP	EnLink Oklahoma Gas Processing, LP or EnLink Oklahoma Gas Processing, LP together with, when applicable, its consolidated subsidiaries. As of January 31, 2019, EOGP is wholly-owned by the Operating 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.
GIP	Global Infrastructure Management, LLC, an independent infrastructure fund manager, itself, its affiliates, or managed fund vehicles, including GIP III Stetson I, L.P., GIP III Stetson II, L.P., and their affiliates.
GIP Transaction	On July 18, 2018, subsidiaries of Devon closed a transaction to sell all of their equity interests in ENLK, ENLC, and the managing member of ENLC to GIP.
GP Plan	EnLink Midstream GP, LLC’s Long-Term Incentive Plan.
Gross Operating Margin	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 the definition and other information.
ISDAs	International Swaps and Derivatives Association Agreements.

Merger	On January 25, 2019, NOLA Merger Sub merged with and into ENLK with ENLK continuing as the surviving entity and a subsidiary of ENLC.
Merger Agreement	The Agreement and Plan of Merger, dated as of October 21, 2018, by and among ENLK, our general partner, ENLC, the managing member of ENLC, and NOLA Merger Sub related to the Merger.
MMbbls	Million barrels.
MMbtu	Million British thermal units.
MMcf	Million cubic feet.
MVC	Minimum volume commitment.
NGL	Natural gas liquid.
NGP	NGP Natural Resources XI, LP.
NOLA Merger Sub	NOLA Merger Sub, LLC, previously a wholly-owned subsidiary of ENLC prior to the Merger.
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 in west Texas and New Mexico.
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	An $850.0 million term loan entered into by ENLK on December 11, 2018 with Bank of America, N.A., as Administrative Agent, Bank of Montreal and Royal Bank of Canada, as Co-Syndication Agents, Citibank, N.A. and Wells Fargo Bank, National Association, as Co-Documentation Agents, and the lenders party thereto, which ENLC assumed in connection with the Merger and the obligations of which ENLK guarantees.
Thunderbird Plant	A gas processing plant in central Oklahoma.
Tiger Plant	A gas processing plant in the Delaware Basin.
White Star	White Star Petroleum Holdings, LLC.

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

	September 30, 2019	December 31, 2018
	(Unaudited)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 101.7	$ 99.5
Accounts receivable:		
Trade, net of allowance for bad debt of $0.5 and $0.3, respectively	44.1	126.3
Accrued revenue and other	450.4	705.9
Related party	8.2	2.1
Fair value of derivative assets	9.6	28.6
Natural gas and NGLs inventory, prepaid expenses, and other	67.5	72.8
Total current assets	681.5	1,035.2
Property and equipment, net of accumulated depreciation of $3,304.4 and $2,967.4, respectively	7,084.2	6,846.7
Intangible assets, net of accumulated amortization of $515.0 and $422.2, respectively	1,280.8	1,373.6
Goodwill	190.3	190.3
Investment in unconsolidated affiliates	78.6	80.1
Fair value of derivative assets	7.9	4.1
Other assets, net	93.5	41.3
Total assets	$ 9,416.8	$ 9,571.3
LIABILITIES AND PARTNERS' EQUITY		
Current liabilities:		
Accounts payable and drafts payable	$ 91.9	$ 105.5
Accounts payable to related party	3.6	4.3
Accrued gas, NGLs, condensate, and crude oil purchases	323.8	500.4
Fair value of derivative liabilities	9.5	21.8
Current maturities of long-term debt	—	399.8
Other current liabilities	267.0	246.7
Total current liabilities	695.8	1,278.5
Long-term debt, including $1,513.5 from related parties	4,576.8	3,919.8
Asset retirement obligations	15.3	14.8
Other long-term liabilities	90.8	20.0
Deferred tax liability	40.9	42.4
Fair value of derivative liabilities	10.2	2.4
Redeemable non-controlling interest	5.5	9.3
Partners' equity:		
Common unitholders (144,358,720 and 353,117,434 units issued and outstanding, respectively)	2,109.2	2,460.8
Series B preferred unitholders (59,450,923 and 58,728,994 units issued and outstanding, respectively)	894.6	889.3
Series C preferred unitholders (400,000 units outstanding)	401.1	395.1
General partner interest (1,594,974 equivalent units outstanding)	218.6	231.2
Accumulated other comprehensive loss	(17.4)	(2.1)
Non-controlling interest	375.4	309.8
Total partners' equity	3,981.5	4,284.1
Total liabilities and partners' equity	$ 9,416.8	$ 9,571.3

See accompanying notes to consolidated financial statements.

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

	Three Months Ended September 30, 2019	Three Months Ended September 30, 2018	Nine Months Ended September 30, 2019	Nine Months Ended September 30, 2018
	(Unaudited)			
Revenues:				
Product sales	$ 1,137.2	$ 1,832.2	$ 4,118.5	$ 4,766.5
Product sales—related parties	—	10.2	—	41.0
Midstream services	263.3	241.5	762.5	476.1
Midstream services—related parties	—	35.8	—	377.2
Gain (loss) on derivative activity	7.5	(5.4)	16.2	(20.1)
Total revenues	1,408.0	2,114.3	4,897.2	5,640.7
Operating costs and expenses:				
Cost of sales	999.5	1,696.6	3,663.0	4,403.7
Operating expenses	119.2	114.7	351.6	337.3
General and administrative	38.3	39.2	108.8	94.5
(Gain) loss on disposition of assets	(3.0)	—	(2.9)	1.3
Depreciation and amortization	157.3	146.7	463.1	430.1
Impairments	—	24.6	—	24.6
Loss on secured term loan receivable	—	—	52.9	—
Total operating costs and expenses	1,311.3	2,021.8	4,636.5	5,291.5
Operating income	96.7	92.5	260.7	349.2
Other income (expense):				
Interest expense, net of interest income	(56.6)	(44.1)	(160.2)	(131.5)
Income from unconsolidated affiliates	4.0	4.3	14.0	11.7
Other income (expense)	(0.2)	0.1	0.1	0.3
Total other expense	(52.8)	(39.7)	(146.1)	(119.5)
Income before non-controlling interest and income taxes	43.9	52.8	114.6	229.7
Income tax benefit (expense)	(0.3)	(0.9)	(0.5)	0.2
Net income	43.6	51.9	114.1	229.9
Net income attributable to non-controlling interest	1.2	3.1	4.8	5.3
Net income attributable to ENLK	$ 42.4	$ 48.8	$ 109.3	$ 224.6

See accompanying notes to consolidated financial statements.

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2019	2018	2019	2018
	(Unaudited)			
Net income	$ 43.6	$ 51.9	$ 114.1	$ 229.9
Loss on designated cash flow hedge	(1.8)	—	(15.3)	—
Comprehensive income	41.8	51.9	98.8	229.9
Comprehensive income attributable to non-controlling interest	1.2	3.1	4.8	5.3
Comprehensive income attributable to ENLK	$ 40.6	$ 48.8	$ 94.0	$ 224.6

See accompanying notes to consolidated financial statements.

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

	Common Units		Series B Preferred Units		Series C Preferred Units		General Partner Interest		Accumulated Other Comprehensive Loss	Non-Controlling Interest	Total	Redeemable Non-controlling interest (Temporary Equity)
	$	Units	$	Units	$	Units	$	Units	$	$	$	$
							(Unaudited)					
Balance, December 31, 2018	$ 2,460.8	353.1	$ 889.3	58.7	$ 395.1	0.4	$ 231.2	1.6	$ (2.1)	$ 309.8	$ 4,284.1	$ 9.3
Adoption of ASC 842	0.3	—	—	—	—	—	—	—	—	—	0.3	—
Balance, January 1, 2019	2,461.1	353.1	889.3	58.7	395.1	0.4	231.2	1.6	(2.1)	309.8	4,284.4	9.3
Conversion of restricted units for common units, net of units withheld for taxes	(2.8)	0.5	—	—	—	—	—	—	—	—	(2.8)	—
Unit-based compensation	1.4	—	—	—	—	—	12.1	—	—	—	13.5	—
Distributions	(139.4)	—	(16.5)	0.5	—	—	(15.6)	—	—	(6.3)	(177.8)	—
Contributions from non-controlling interests	—	—	—	—	—	—	—	—	—	15.7	15.7	—
Fair value adjustment related to redeemable non-controlling interest	2.1	—	—	—	—	—	—	—	—	—	2.1	(2.1)
Issuance of common units to ENLC for acquisition of EOGP	—	55.8	—	—	—	—	—	—	—	—	—	—
Conversion of ENLK common units into ENLC units	—	(265.0)	—	—	—	—	—	—	—	—	—	—
Net income (loss)	47.5	—	18.6	—	6.0	—	(9.3)	—	—	2.9	65.7	—
Balance, March 31, 2019	2,369.9	144.4	891.4	59.2	401.1	0.4	218.4	1.6	(2.1)	322.1	4,200.8	7.2
Unit-based compensation	—	—	—	—	—	—	6.4	—	—	—	6.4	—
Distributions	(137.2)	—	(16.7)	0.1	(12.0)	—	—	—	—	(6.4)	(172.3)	—
Contributions from non-controlling interests	—	—	—	—	—	—	—	—	—	29.5	29.5	—
Loss on designated cash flow hedge	—	—	—	—	—	—	—	—	(13.5)	—	(13.5)	—
Fair value adjustment related to redeemable non-controlling interest	1.4	—	—	—	—	—	—	—	—	—	1.4	(1.4)
Net income (loss)	(13.8)	—	18.5	—	6.0	—	(6.6)	—	—	0.7	4.8	—
Balance, June 30, 2019	2,220.3	144.4	893.2	59.3	395.1	0.4	218.2	1.6	(15.6)	345.9	4,057.1	5.8
Unit-based compensation	—	—	—	—	—	—	11.1	—	—	—	11.1	—
Distributions	(139.8)	—	(17.1)	0.2	—	—	—	—	—	(5.0)	(161.9)	(0.3)
Contributions from non-controlling interests	—	—	—	—	—	—	—	—	—	33.4	33.4	—
Loss on designated cash flow hedge	—	—	—	—	—	—	—	—	(1.8)	—	(1.8)	—
Fair value adjustment related to redeemable non-controlling interest	0.1	—	—	—	—	—	—	—	—	—	0.1	(0.1)
Net income (loss)	28.6	—	18.5	—	6.0	—	(10.7)	—	—	1.1	43.5	0.1
Balance, September 30, 2019	$ 2,109.2	144.4	$ 894.6	59.5	$ 401.1	0.4	$ 218.6	1.6	$ (17.4)	$ 375.4	$ 3,981.5	$ 5.5

See accompanying notes to consolidated financial statements.

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

	Common Units		Series B Preferred Units		Series C Preferred Units		General Partner Interest		Accumulated Other Comprehensive Loss	Non-Controlling Interest	Total	Redeemable Non-Controlling Interest (Temporary Equity)
	$	Units	$	Units	$	Units	$	Units	$	$	$	$
							(Unaudited)					
Balance, December 31, 2017	$ 3,108.6	349.7	$ 864.1	57.1	$ 395.1	0.4	$ 206.6	1.6	$ (2.1)	$ 233.2	$ 4,805.5	$ 4.6
Issuance of common units	0.9	0.1	—	—	—	—	—	—	—	—	0.9	—
Conversion of restricted units for common units, net of units withheld for taxes	(2.7)	0.4	—	—	—	—	—	—	—	—	(2.7)	—
Unit-based compensation	4.4	—	—	—	—	—	4.4	—	—	—	8.8	—
Distributions	(137.6)	—	(16.0)	0.4	—	—	(15.4)	—	—	(10.0)	(179.0)	—
Contributions from non-controlling interests	—	—	—	—	—	—	—	—	—	33.3	33.3	—
Adjustment for acquisition of EOGP (Note 1)	2.8	—	—	—	—	—	—	—	—	(2.8)	—	—
Net income	21.6	—	21.9	—	6.0	—	14.8	—	—	0.8	65.1	—
Balance, March 31, 2018	2,998.0	350.2	870.0	57.5	401.1	0.4	210.4	1.6	(2.1)	254.5	4,731.9	4.6
Conversion of restricted units for common units, net of units withheld for taxes	(0.7)	0.1	—	—	—	—	—	—	—	—	(0.7)	—
Unit-based compensation	4.0	—	—	—	—	—	4.0	—	—	—	8.0	—
Distributions	(137.4)	—	(16.2)	0.4	(12.0)	—	(15.5)	—	—	(13.4)	(194.5)	—
Contributions from non-controlling interests	—	—	—	—	—	—	—	—	—	48.3	48.3	—
Adjustment for acquisition of EOGP (Note 1)	6.6	—	—	—	—	—	—	—	—	(6.6)	—	—
Net income	58.9	—	22.8	—	6.0	—	23.8	—	—	1.4	112.9	—
Balance, June 30, 2018	2,929.4	350.3	876.6	57.9	395.1	0.4	222.7	1.6	(2.1)	284.2	4,705.9	4.6
Issuance of common units	45.2	2.5	—	—	—	—	—	—	—	—	45.2	—
Conversion of restricted units for common units, net of units withheld for taxes	(2.2)	0.3	—	—	—	—	—	—	—	—	(2.2)	—
Unit-based compensation	8.0	—	—	—	—	—	7.3	—	—	—	15.3	—
Distributions	(138.0)	—	(16.3)	0.4	—	—	(15.4)	—	—	(14.2)	(183.9)	—
Contributions from non-controlling interests	—	—	—	—	—	—	—	—	—	40.4	40.4	—
Fair value adjustment related to redeemable non-controlling interest	(1.4)	—	—	—	—	—	—	—	—	—	(1.4)	1.4
Adjustment for acquisition of EOGP (Note 1)	11.1	—	—	—	—	—	—	—	—	(11.1)	—	—
Net income	5.2	—	24.3	—	6.0	—	13.3	—	—	2.9	51.7	0.2
Balance, September 30, 2018	$ 2,857.3	353.1	$ 884.6	58.3	$ 401.1	0.4	$ 227.9	1.6	$ (2.1)	$ 302.2	$ 4,671.0	$ 6.2

See accompanying notes to consolidated financial statements.

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

	Nine Months Ended September 30, 2019	2018
	(Unaudited)	
Cash flows from operating activities:		
Net income	$ 114.1	$ 229.9
Adjustments to reconcile net income to net cash provided by operating activities:		
Impairments	—	24.6
Depreciation and amortization	463.1	430.1
Loss on secured term loan receivable	52.9	—
Non-cash unit-based compensation	31.0	31.6
(Gain) loss on derivatives recognized in net income	(16.2)	20.1
Cash settlements on derivatives	12.5	(4.3)
Amortization of debt issue costs, net discount (premium) of notes	3.9	3.2
Distribution of earnings from unconsolidated affiliates	14.7	14.0
Income from unconsolidated affiliates	(14.0)	(11.7)
Non-cash revenue from contract restructuring	—	(45.5)
Other operating activities	(6.5)	(2.2)
Changes in assets and liabilities:		
Accounts receivable, accrued revenue, and other	331.6	(292.2)
Natural gas and NGLs inventory, prepaid expenses, and other	1.9	(92.9)
Accounts payable, accrued product purchases, and other accrued liabilities	(219.2)	239.1
Net cash provided by operating activities	769.8	543.8
Cash flows from investing activities:		
Additions to property and equipment	(594.5)	(639.4)
Proceeds from sale of property	13.7	1.5
Other investing activities	(2.2)	4.9
Net cash used in investing activities	(583.0)	(633.0)
Cash flows from financing activities:		
Proceeds from borrowings	3,593.5	1,979.0
Payments on borrowings	(3,330.0)	(1,214.0)
Payment of installment payable for EOGP acquisition	—	(250.0)
Debt financing costs	(10.0)	—
Proceeds from issuance of common units	—	46.1
Distributions to non-controlling interests	(18.0)	(37.6)
Contributions by non-controlling interests, including contributions from affiliates of $48.6 for the nine months ended September 30, 2018	78.6	122.0
Distributions to Series B Preferred Units	(50.3)	(48.5)
Distributions to Series C Preferred Units	(12.0)	(12.0)
Distributions to common unitholders and to general partner	(432.0)	(459.3)
Other financing activities	(4.4)	(3.7)
Net cash provided by (used in) financing activities	(184.6)	122.0
Net increase in cash and cash equivalents	2.2	32.8
Cash and cash equivalents, beginning of period	99.5	30.8
Cash and cash equivalents, end of period	$ 101.7	$ 63.6
Supplemental disclosures of cash flow information:		
Cash paid for interest	$ 127.7	$ 106.3
Cash paid for income taxes	$ 2.1	$ 0.6
Non-cash investing activities:		
Non-cash accrual of property and equipment	$ 24.6	$ 13.3
Discounted secured term loan receivable from contract restructuring	$ —	$ 47.7

See accompanying notes to consolidated financial statements.

ENLINK MIDSTREAM PARTNERS, LP AND SUBSIDIARIES
Notes to Consolidated Financial Statements
September 30, 2019
(Unaudited)

(1) General

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

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

a. Organization of Business

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

EnLink Midstream GP, LLC, a Delaware limited liability company, is our general partner. Our general partner manages our operations and activities. Our general partner is a direct, wholly-owned subsidiary of ENLC. ENLC's units are traded on the New York Stock Exchange under the symbol "ENLC." ENLC's managing member is a wholly-owned subsidiary of GIP.

Transfer of EOGP Interest

On January 31, 2019, ENLC transferred its16.1% limited partner interest in EOGP to the Operating Partnership in exchange for55,827,221 ENLK common units, resulting in the Operating Partnership owning 100% of the limited partner interests in EOGP. This acquisition has been accounted for as an acquisition under common control under ASC 805, *Business Combinations*, resulting in the retrospective adjustment of our prior results. The "Adjustment for acquisition of EOGP (Note 1)" presented in the consolidated statements of changes in partners' equity for the period ended June 30, 2018 represents the adjustment due to the recast to offset distributions paid to ENLC and contributions received from ENLC for its related ownership in EOGP.

Simplification of the Corporate Structure

On October 21, 2018, ENLK, ENLC, the general partner of ENLK, the managing member of ENLC, and NOLA Merger Sub entered into the Merger Agreement pursuant to which, on January 25, 2019, NOLA Merger Sub merged with and into ENLK, with ENLK continuing as the surviving entity and as a subsidiary of ENLC. As a result of the Merger:

- Each issued and outstanding ENLK common unit (except for ENLK common units held by ENLC and its subsidiaries) was converted into1.15 ENLC common units, which resulted in ENLC owning all of the remaining outstanding ENLK common units.
- Our general partner's incentive distribution rights in ENLK were eliminated.
- The Series B Preferred Units continue to be issued and outstanding, except that certain terms of the Series B Preferred Units have been modified pursuant to an amended partnership agreement of ENLK. See "Note 7—Partners' Capital" for additional information regarding the modified terms of the Series B Preferred Units.
- ENLC issued to Enfield, the current holder of the Series B Preferred Units, for no additional consideration, ENLC Class C Common Units equal to the number of Series B Preferred Units held by Enfield immediately prior to the effective time of the Merger, in order to provide Enfield with certain voting rights with respect to ENLC. For each additional Series B Preferred Unit issued by ENLK in quarterly in-kind distributions, ENLC will issue an additional ENLC Class C Common Unit to the applicable holder of such Series B Preferred Unit. In addition, for each Series B Preferred Unit that is exchanged into an ENLC common unit, an ENLC Class C Common Unit will be canceled.

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

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

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

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

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

b. Nature of Business

We primarily focus on providing midstream energy services, including:

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

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.

(2) Significant Accounting Policies

a. Basis of Presentation

The accompanying consolidated financial statements are 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, 2018. Certain reclassifications were made to the financial statements for the prior period to conform to current period presentation. The effect of these reclassifications had no impact on previously reported partners' equity or net income. All significant intercompany balances and transactions have been eliminated in consolidation.

b. Revenue Recognition

Minimum Volume Commitments and Firm Transportation Contracts

Certain of our gathering and processing agreements provide for quarterly or annual MVCs. Under these agreements, our customers or suppliers agree to ship and/or process a minimum volume of product on our systems over an agreed time period. If a customer or supplier under such an agreement fails to meet its MVC for a specified period, the customer is obligated to pay a contractually-determined fee based upon the shortfall between actual product volumes and the MVC for that period. Some of these agreements also contain make-up right provisions that allow a customer or supplier to utilize gathering or processing fees in excess of the MVC in subsequent periods to offset shortfall amounts in previous periods. We record revenue under MVC contracts during periods of shortfall when it is known that the customer cannot, or will not, make up the deficiency in subsequent periods. Deficiency fee revenue is included in midstream services revenue.

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

The following table summarizes the contractually committed fees that we expect to recognize in our consolidated statements of operations, in either revenue or reductions to cost of sales, from MVC and firm transportation contractual provisions. All amounts in the table below are determined using the contractually-stated MVC or firm transportation volumes specified for each period multiplied by the relevant deficiency or reservation fee. Actual amounts could differ due to the timing of revenue recognition or reductions to cost of sales resulting from make-up right provisions included in our agreements, as well as due to nonpayment or nonperformance by our customers. These fees do not represent the shortfall amounts we expect to collect under our MVC contracts, as we generally do not expect volume shortfalls to equal the full amount of the contractual MVCs during these periods. For example, for the three and nine months ended September 30, 2019, we had contractual commitments of $38.9 million and $113.6 million under our MVC contracts, respectively, and recorded $6.5 million and $14.2 million of revenue due to volume shortfalls, respectively.

MVC and Firm Transportation Commitments (1)		
2019 (remaining)	$	58.9
2020		259.8
2021		108.1
2022		94.7
2023		85.7
Thereafter		237.0
Total	$	844.2

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

c. Secured Term Loan Receivable

In late May 2019, White Star, the counterparty to our $58.0 million second lien secured term loan receivable, filed for reorganization under Chapter 11 of the U.S. Bankruptcy Code. Under the original term loan agreement executed in May 2018, White Star was scheduled to make an installment payment of $19.5 million in April 2019. In November 2018 and again in February 2019, we amended the installment payment terms with the result that the single 2019 installment payment was split into two payments of $9.75 million in May 2019 and $10.75 million in October 2019. White Star defaulted on its May 2019 installment payment prior to filing for reorganization under Chapter 11 of the U.S. Bankruptcy Code. While the outcome of the bankruptcy proceeding is not yet finalized, we do not believe that it is probable that White Star will be able to repay the outstanding amounts owed to us under the second lien secured term loan. As a result, we have recorded a $52.9 million loss in our consolidated statement of operations for the nine months ended September 30, 2019, which represents a full write-down of the second lien secured term loan.

d. Accounting Standards to be Adopted in Future Periods

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

e. Adopted Accounting Standards

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

(3) Goodwill and Intangible Assets

Goodwill

During the third quarter of 2019, we performed an interim impairment test due to a significant decline in ENLC's unit price from the first quarter and downward revisions in our estimated future cash flows due to delays in development plans announced by certain of our major customers. We determined that no impairments of goodwill were required as of September 30, 2019.

Intangible Assets

Intangible assets associated with customer relationships are amortized on a straight-line basis over the expected period of benefits of the customer relationships, which range from 5 to 20 years.

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

	Gross Carrying Amount	Accumulated Amortization	Net Carrying Amount
Nine Months Ended September 30, 2019			
Customer relationships, beginning of period	$ 1,795.8	$ (422.2)	$ 1,373.6
Amortization expense	—	(92.8)	(92.8)
Customer relationships, end of period	$ 1,795.8	$ (515.0)	$ 1,280.8

The weighted average amortization period is 15.0 years. Amortization expense was $30.9 million for each of the three months ended September 30, 2019 and 2018, and $92.8 million and $92.6 million for the nine months ended September 30, 2019 and 2018, respectively.

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

2019 (remaining)	$ 30.9
2020	123.7
2021	123.7
2022	123.7
2023	123.6
Thereafter	755.2
Total	$ 1,280.8

(4) Related Party Transactions

a. Transactions with ENLC

Simplification of the Corporate Structure. On October 21, 2018, ENLK, ENLC, the general partner of ENLK, the managing member of ENLC, and NOLA Merger Sub entered into the Merger Agreement pursuant to which, on January 25, 2019, NOLA Merger Sub merged with and into ENLK, with ENLK continuing as the surviving entity and as a subsidiary of ENLC. See "Note 1—General" for more information on this transaction.

Transfer of EOGP Interest. On January 31, 2019, ENLC transferred its 16.1% limited partner interest in EOGP to the Operating Partnership in exchange for 55,827,221 ENLK common units, resulting in the Operating Partnership owning 100% of the limited partner interests in EOGP.

Related Party Debt. Related party debt includes borrowings under the Consolidated Credit Facility, the Term Loan, and ENLC's 5.375% senior unsecured notes to fund the operations and growth capital expenditures of ENLK through a related party arrangement with ENLC. See "Note 6—Long-Term Debt" for more information on this arrangement.

We had accounts receivable balances related to transactions with ENLC of $8.2 million and $1.4 million at September 30, 2019 and December 31, 2018, respectively.

b. Transactions with Devon

On July 18, 2018, subsidiaries of Devon sold all of their equity interests in ENLK, ENLC, and the managing member of ENLC to GIP for aggregate consideration of $3.125 billion. Accordingly, Devon is no longer an affiliate of ENLK or ENLC. The sale did not affect our commercial arrangements with Devon, except that Devon agreed to extend through 2029 certain existing fixed-fee gathering and processing contracts related to the Bridgeport plant in north Texas and the Cana plant in Oklahoma. Prior to July 18, 2018, revenues from transactions with Devon are included in "Product sales—related parties" or "Midstream services—related parties" in the consolidated statement of operations. Revenues from transactions with Devon after July 18, 2018 are included in "Product sales" or "Midstream services" in the consolidated statement of operations.

For the three and nine months ended September 30, 2018, related party revenues from Devon accounted for 2.0% and 7.3%, respectively, of our revenues.

c. Transactions with Cedar Cove JV

For the three and nine months ended September 30, 2019, we recorded cost of sales of $4.1 million and $18.0 million, respectively, and for the three and nine months ended September 30, 2018, we recorded cost of sales of $11.3 million and $33.8 million, respectively, related to our purchase of residue gas and NGLs from the Cedar Cove JV subsequent to processing at our central Oklahoma processing facilities. We had no accounts receivable balances related to transactions with the Cedar Cove JV at September 30, 2019 and $0.7 million at December 31, 2018. Additionally, we had accounts payable balances related to transactions with the Cedar Cove JV of $1.6 million and $4.3 million at September 30, 2019 and December 31, 2018, respectively.

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

(5) Leases

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

- *Office space.* Our primary offices are in Dallas, Houston, and Midland, with smaller offices in other locations near our assets. Our office leases are long-term in nature and represent $61.3 million of our lease liability and $40.6 million of our right-of-use asset as of September 30, 2019. These office leases typically include variable lease costs related to utility expenses, which are determined based on our pro-rata share of the building expenses each month and expensed as incurred.
- *Compression and other field equipment.* We pay third parties to provide compressors or other field equipment for our assets. Under these agreements, a third party installs and operates compressor units based on specifications set by us to meet our compression needs at specific locations. While the third party determines which compressors to install and operates and maintains the units, we have the right to control the use of the compressors and are the sole economic beneficiary of the identified assets. These agreements are typically for an initial term of one to three years but will automatically renew from month to month until canceled by us or the lessor. Compression and other field equipment rentals represent $26.4 million of our lease liability and $26.3 million of our right-of-use asset as of September 30, 2019. Under certain agreements, we may incur variable lease costs related to incidental services provided by the equipment lessor, which are expensed as incurred.

- *Office equipment.* We rent office equipment for a monthly fee. These leases are typically for several years and represent $0.7 million of our lease liability and $0.7 million of our right-of-use asset as of September 30, 2019.

- *Land and land easements.* We make periodic payments to lease land or to have access to our assets. Land leases and easements are typically long-term to match the expected useful life of the corresponding asset and represent $15.1 million of our lease liability and $13.0 million of our right-of-use asset as of September 30, 2019.

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

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

	September 30, 2019
Operating leases:	
Other assets, net	$ 80.6
Other current liabilities	$ 21.3
Other long-term liabilities	$ 82.2
Other lease information	
Weighted-average remaining lease term—Operating leases	10.7 years
Weighted-average discount rate—Operating leases	5.2 %

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

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

	Three Months Ended September 30, 2019	Nine Months Ended September 30, 2019
Finance lease expense:		
Amortization of right-of-use asset	$ 2.2	$ 5.2
Interest on lease liability	0.1	0.1
Operating lease expense:		
Long-term operating lease expense	7.2	21.8
Short-term lease expense	9.5	25.3
Variable lease expense	1.3	4.3
Total lease expense	$ 20.3	$ 56.7

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

	Three Months Ended September 30, 2019	Nine Months Ended September 30, 2019
Supplemental cash flow information:		
Cash payments for finance leases included in cash flows from financing activities	$ 0.4	$ 1.2
Cash payments for operating leases included in cash flows from operating activities	$ 7.2	$ 22.6
Right-of-use assets obtained in exchange for operating lease liabilities	$ 3.2	$ 98.4

The following table summarizes the maturity of our lease liability as of September 30, 2019 (in millions):

	Total	2019 (remaining)	2020	2021	2022	2023	Thereafter
Undiscounted operating lease liability	$ 142.7	$ 6.7	$ 23.5	$ 17.1	$ 10.2	$ 9.0	$ 76.2
Reduction due to present value	(39.2)	(1.3)	(4.5)	(3.8)	(3.4)	(3.1)	(23.1)
Operating lease liability	103.5	5.4	19.0	13.3	6.8	5.9	53.1
Total lease liability	$ 103.5	$ 5.4	$ 19.0	$ 13.3	$ 6.8	$ 5.9	$ 53.1

(6) Long-Term Debt

As of September 30, 2019 and December 31, 2018, long-term debt consisted of the following (in millions):

	September 30, 2019			December 31, 2018		
	Outstanding Principal	Premium (Discount)	Long-Term Debt	Outstanding Principal	Premium (Discount)	Long-Term Debt
Related party debt	$ 1,513.5	$ —	$ 1,513.5	$ —	$ —	$ —
Term Loan due 2021 (1)	—	—	—	850.0	—	850.0
2.70% Senior unsecured notes due 2019 (2)	—	—	—	400.0	—	400.0
4.40% Senior unsecured notes due 2024	550.0	1.6	551.6	550.0	1.8	551.8
4.15% Senior unsecured notes due 2025	750.0	(0.7)	749.3	750.0	(0.9)	749.1
4.85% Senior unsecured notes due 2026	500.0	(0.5)	499.5	500.0	(0.5)	499.5
5.60% Senior unsecured notes due 2044	350.0	(0.2)	349.8	350.0	(0.2)	349.8
5.05% Senior unsecured notes due 2045	450.0	(6.0)	444.0	450.0	(6.2)	443.8
5.45% Senior unsecured notes due 2047	500.0	(0.1)	499.9	500.0	(0.1)	499.9
Debt classified as long-term, including current maturities of long-term debt	$ 4,613.5	$ (5.9)	4,607.6	$ 4,350.0	$ (6.1)	4,343.9
Debt issuance cost (3)			(30.8)			(24.3)
Less: Current maturities of long-term debt (2)			—			(399.8)
Long-term debt, net of unamortized issuance cost			$ 4,576.8			$ 3,919.8

(1) In December 2018, ENLK entered into an $850.0 million, three-year unsecured Term Loan. Borrowings under the Term Loan bear interest based on Prime and/or LIBOR plus an applicable margin. The effective interest rate was 3.9% at December 31, 2018. In connection with the closing of the Merger, the Term Loan was assumed by ENLC, and we became a guarantor of the Term Loan.

(2) The 2.70% senior unsecured notes matured on April 1, 2019. Therefore, the outstanding principal balance, net of discount and debt issuance costs, is classified as “Current maturities of long-term debt” on the consolidated balance sheet as of December 31, 2018.

(3) Net of amortization of $9.8 million and $15.3 million at September 30, 2019 and December 31, 2018, respectively.

Related Party Debt

Related party debt includes borrowings under the Consolidated Credit Facility, the Term Loan, and ENLC’s5.375% senior unsecured notes to fund the operations and growth capital expenditures of ENLK through a related party arrangement with ENLC. Interest charged to ENLK for borrowings made through the related party arrangement will be the same as interest charged to ENLC on borrowings under the Consolidated Credit Facility, the Term Loan, and ENLC’s 5.375% senior unsecured notes. As of September 30, 2019, $1,513.5 million of related party debt is included in “Long-term debt” in the consolidated balance sheet related to these borrowings.

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

Issuance and Repayment of Senior Unsecured Notes

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

Consolidated Credit Facility

On December 11, 2018, ENLC entered into the Consolidated Credit Facility, which permits ENLC to borrow up to $1.75 billion on a revolving credit basis and includes a $500.0 million letter of credit subfacility. The Consolidated Credit Facility became available for borrowings and letters of credit upon closing of the Merger. In addition, ENLK became a guarantor under the Consolidated Credit Facility upon the closing of the Merger. In the event that ENLC defaults on the Consolidated Credit Facility, ENLK will be liable for the entire outstanding balance ($275.0 million as of September 30, 2019), and 105% of the outstanding letters of credit under the Consolidated Credit Facility ($4.0 million as of September 30, 2019). The obligations under the Consolidated Credit Facility are unsecured.

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

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

Borrowings under the Consolidated Credit Facility bear interest at ENLC’s option at the Eurodollar Rate (the LIBOR Rate) plus an applicable margin (ranging from 1.125% to 2.00%) or the Base Rate (the highest of the Federal Funds Rate plus 0.50%, the 30-day Eurodollar Rate plus 1.0% or the administrative agent’s prime rate) plus an applicable margin (ranging from 0.125% to 1.00%). The applicable margins vary depending on ENLC’s debt rating. Upon breach by ENLC of certain covenants governing the Consolidated Credit Facility, amounts outstanding under the Consolidated Credit Facility, if any, may become due and payable immediately.

At September 30, 2019, ENLC was in compliance with and expects to be in compliance with the covenants of the Consolidated Credit Facility for at least the next twelve months. Accordingly, we do not expect to make payments related to our guarantee of the $275.0 million outstanding on the Consolidated Credit Facility.

Term Loan

On December 11, 2018, ENLK entered into the Term Loan with Bank of America, N.A., as Administrative Agent, Bank of Montreal and Royal Bank of Canada, as Co-Syndication Agents, Citibank, N.A. and Wells Fargo Bank, National Association, as Co-Documentation Agents, and the lenders party thereto. On December 11, 2018, ENLK borrowed $850.0 million under the Term Loan and used the net proceeds to repay obligations outstanding under the ENLK Credit Facility. 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, the outstanding balance immediately becomes due, and ENLK will be liable for any amount owed on the Term Loan not paid by ENLC. The outstanding balance of the Term Loan was $850.0 million as of September 30, 2019. The obligations under the Term Loan are unsecured.

The Term Loan will mature on December 10, 2021. The Term Loan contains certain financial, operational, and legal covenants. The financial covenants are tested on a quarterly basis, based on the rolling four-quarter period that ends on the last day of each fiscal quarter. The financial covenants include (i) maintaining a ratio of consolidated EBITDA (as defined in the Term Loan, which term includes projected EBITDA from certain capital expansion projects) to consolidated interest charges of no less than 2.5 to 1.0 at all times prior to the occurrence of an investment grade event (as defined in the Term Loan) and (ii) maintaining a ratio of consolidated indebtedness to consolidated EBITDA of no more than 5.0 to 1.0. If ENLC consummates one or more acquisitions in which the aggregate purchase price is $50.0 million or more, ENLC can elect to increase the maximum allowed ratio of consolidated indebtedness to consolidated EBITDA to 5.5 to 1.0 for the quarter in which the acquisition occurs and the three subsequent quarters.

Borrowings under the Term Loan bear interest at ENLC's option at the Eurodollar Rate (the LIBOR Rate) plus an applicable margin (ranging from 1.0% to 1.75%) or the Base Rate (the highest of the Federal Funds Rate plus 0.5%, the 30-day Eurodollar Rate plus 1.0% or the administrative agent's prime rate) plus an applicable margin (ranging from 0.0% to 0.75%). The applicable margins vary depending on ENLC's debt rating. Upon breach by ENLC of certain covenants included in the Term Loan, amounts outstanding under the Term Loan may become due and payable immediately.

At September 30, 2019, ENLC was in compliance with and expects to be in compliance with the covenants of the Term Loan for at least the next twelve months. Accordingly, we do not expect to make payments related to our guarantee of the $850.0 million outstanding on the Term Loan.

(7) Partners' Capital

a. Series B Preferred Units

Prior to the closing of the Merger, Series B Preferred Unit distributions were payable quarterly in cash at an amount equal to $0.28125 per Series B Preferred Unit (the "Cash Distribution Component") plus an in-kind distribution equal to the greater of (A) 0.0025 Series B Preferred Units per Series B Preferred Unit and (B) an amount equal to (i) the excess, if any, of the distribution that would have been payable had the Series B Preferred Units converted into ENLK common units over the Cash Distribution Component, divided by (ii) the issue price of $15.00 (the "Issue Price").

Following the closing of the Merger, and beginning with the quarter ended March 31, 2019, the holder of the Series B Preferred Units is entitled to quarterly cash distributions and distributions in-kind of additional Series B Preferred Units as described below. The quarterly in-kind distribution (the "Series B PIK Distribution") equals the greater of (A) 0.0025 Series B Preferred Units per Series B Preferred Unit and (B) the number of Series B Preferred Units equal to the quotient of (x) the excess (if any) of (1) the distribution that would have been payable by ENLC had the Series B Preferred Units been exchanged for ENLC common units but applying a one-to-one exchange ratio (subject to certain adjustments) instead of the exchange ratio of 1.15 ENLC common units for each Series B Preferred Unit, subject to certain adjustments (the "Series B Exchange Ratio"), over (2) the Cash Distribution Component, divided by (y) the Issue Price. The quarterly cash distribution consists of the Cash Distribution Component plus an amount in cash that will be determined based on a comparison of the value (applying the Issue Price) of (i) the Series B PIK Distribution and (ii) the Series B Preferred Units that would have been distributed in the Series B PIK Distribution if such calculation applied the Series B Exchange Ratio instead of the one-to-one ratio (subject to certain adjustments).

Income is allocated to the Series B Preferred Units in an amount equal to the quarterly distribution with respect to the period earnedA summary of the distribution activity relating to the Series B Preferred Units during the nine months ended September 30, 2019 and 2018 is provided below:

Declaration period	Distribution paid as additional Series B Preferred Units	Cash Distribution (in millions)	Date paid/payable
2019			
Fourth Quarter of 2018	425,785	$ 16.5	February 13, 2019
First Quarter of 2019	147,887	$ 16.7	May 14, 2019
Second Quarter of 2019	148,257	$ 17.1	August 13, 2019
Third Quarter of 2019	148,627	$ 17.1	November 13, 2019
2018			
Fourth Quarter of 2017	413,658	$ 16.0	February 13, 2018
First Quarter of 2018	416,657	$ 16.2	May 14, 2018
Second Quarter of 2018	419,678	$ 16.3	August 13, 2018
Third Quarter of 2018	422,720	$ 16.4	November 13, 2018

b. Series C Preferred Units

Distributions on the Series C Preferred Units accrue and are cumulative from the date of original issue and payable semi-annually in arrears on the 15th day of June and December of each year through and including December 15, 2022 and, thereafter, quarterly in arrears on the 15th day of March, June, September, and December of each year, in each case, if and when declared by our general partner out of legally available funds for such purpose. The initial distribution rate for the Series C Preferred Units from and including the date of original issue to, but not including, December 15, 2022 is 6.0% per annum. On and after December 15, 2022, distributions on the Series C Preferred Units will accumulate for each distribution period at a percentage of the $1,000 liquidation preference per unit equal to an annual floating rate of the three-month LIBOR plus a spread of 4.11%. Income is allocated to the Series C Preferred Units in an amount equal to the earned distributions for the respective reporting period.

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

c. Common Unit Distributions

Following the Merger, we distributed $139.8 million and $277.0 million to ENLC related to its ownership of our common units for the three and nine months ended September 30, 2019, respectively.

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

Declaration period	Distribution/unit		Date paid/payable
2019			
Fourth Quarter of 2018	$	0.39	February 13, 2019
2018			
Fourth Quarter of 2017	$	0.39	February 13, 2018
First Quarter of 2018	$	0.39	May 14, 2018
Second Quarter of 2018	$	0.39	August 13, 2018
Third Quarter of 2018	$	0.39	November 13, 2018

d. Allocation of ENLK Income

Prior to the closing of the Merger and for the three and nine months ended September 30, 2018, net income was allocated to our general partner in an amount equal to its incentive distribution rights. Prior to the closing of the Merger, we were required to pay our general partner incentive distributions in the amount of 13.0% of ENLK distributions in excess of $0.25 per unit, 23.0% of ENLK distributions in excess of $0.3125 per unit, and 48.0% of ENLK distributions in excess of $0.375 per unit. Our general partner was not entitled to incentive distributions with respect to (i) distributions on the Series B Preferred Units until such units converted into common units or (ii) the Series C Preferred Units. At the closing of the Merger, our general partner's incentive distribution rights were eliminated.

For the three and nine months ended September 30, 2018, our general partner's share of net income consisted of incentive distribution rights to the extent earned, a deduction for unit-based compensation attributable to ENLC's restricted units, and the percentage interest of our net income adjusted for ENLC's unit-based compensation specifically allocated to our general partner. The net income allocated to our general partner is as follows (in millions):

	Three Months Ended September 30,				Nine Months Ended September 30,			
	2019		2018		2019		2018	
Income allocation for incentive distributions	$	—	$	15.0	$	—	$	44.6
Unit-based compensation attributable to ENLC's restricted and performance units		(11.1)		(7.3)		(29.6)		(15.7)
General partner share of net income		0.4		—		0.6		0.6
General partner interest in EOGP acquisition		—		5.6		2.4		22.4
General partner interest in net income (loss)	$	(10.7)	$	13.3	$	(26.6)	$	51.9

(8) Investment in Unconsolidated Affiliates

As of September 30, 2019, 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 September 30,		Nine Months Ended September 30,	
	2019	2018	2019	2018
GCF				
Distributions	$ 5.1	$ 5.3	$ 14.7	$ 16.4
Equity in income	$ 4.4	$ 4.6	$ 15.3	$ 14.0
Cedar Cove JV				
Contributions	$ —	$ —	$ —	$ 0.1
Distributions	$ 0.3	$ —	$ 0.8	$ 0.3
Equity in loss	$ (0.4)	$ (0.3)	$ (1.3)	$ (2.3)
Total				
Contributions	$ —	$ —	$ —	$ 0.1
Distributions	$ 5.4	$ 5.3	$ 15.5	$ 16.7
Equity in income	$ 4.0	$ 4.3	$ 14.0	$ 11.7

The following table shows the balances related to our investment in unconsolidated affiliates as of September 30, 2019 and December 31, 2018 (in millions):

	September 30, 2019	December 31, 2018
GCF	$ 42.5	$ 41.9
Cedar Cove JV	36.1	38.2
Total investment in unconsolidated affiliates	$ 78.6	$ 80.1

(9) Employee Incentive Plans

a. Long-Term Incentive Plans

Prior to the Merger, ENLC and ENLK each had similar unit-based compensation payment plans for officers and employees. ENLC grants unit-based awards under the 2014 Plan, and ENLK granted unit-based awards under the GP Plan. As of the closing of the Merger, (i) ENLC assumed all obligations in respect of the GP Plan and the outstanding awards granted thereunder (the "Legacy ENLK Awards") and (ii) the Legacy ENLK Awards converted into ENLC unit-based awards using the 1.15 exchange ratio (as defined in the Merger Agreement) as the conversion rate. In addition, as of the closing of the Merger, the performance metric of each Legacy ENLK Award and each then outstanding award under the 2014 Plan with performance-based vesting conditions was modified as discussed in (c) and (e) below. Following the consummation of the Merger, no additional awards will be granted under the GP Plan.

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

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2019	2018	2019	2018
Cost of unit-based compensation charged to operating expense	$ 2.1	$ 5.2	$ 4.5	$ 9.5
Cost of unit-based compensation charged to general and administrative expense	10.0	11.8	26.5	22.1
Total unit-based compensation expense	$ 12.1	$ 17.0	$ 31.0	$ 31.6

b. EnLink Midstream Partners, LP Restricted Incentive Units

ENLK restricted incentive units were valued at their fair value at the date of grant, which is equal to the market value of ENLK common units on such date. A summary of the restricted incentive unit activity for the nine months ended September 30, 2019 is provided below:

	Nine Months Ended September 30, 2019	
EnLink Midstream Partners, LP Restricted Incentive Units:	Number of Units	Weighted Average Grant-Date Fair Value
Non-vested, beginning of period	2,556,270	$ 14.43
Vested (1)	(722,853)	10.02
Forfeited	(4,490)	11.93
Converted to ENLC (2)	(1,828,927)	16.11
Non-vested, end of period	—	$ —

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

A summary of the restricted incentive units' aggregate intrinsic value (market value at vesting date) and fair value of units vested (market value at date of grant) for the three and nine months ended September 30, 2019 and 2018 is provided below (in millions). Since the Legacy ENLK Awards converted into ENLC unit-based awards as a result of the Merger, no additional restricted incentive units will vest as ENLK units under the GP Plan (such restricted incentive units, as converted, are eligible to vest as ENLC units) and no additional expense will be recognized after January 25, 2019 under the GP Plan.

	Three Months Ended September 30,		Nine Months Ended September 30,	
EnLink Midstream Partners, LP Restricted Incentive Units:	**2019**	**2018**	**2019**	**2018**
Aggregate intrinsic value of units vested	$ —	$ 3.7	$ 8.0	$ 12.8
Fair value of units vested	$ —	$ 2.8	$ 7.2	$ 16.1

c. EnLink Midstream Partners, LP Performance Units

Prior to the Merger, our general partner granted performance awards under the GP Plan. The performance award agreements provided that the vesting of performance units (i.e., performance-based restricted incentive units) granted thereunder was dependent on the achievement of certain total shareholder return ("TSR") performance goals relative to the TSR achievement of a peer group of companies (the "Peer Companies") over the applicable performance period. The performance award agreements contemplated that the Peer Companies for an individual performance award (the "Subject Award") were the companies comprising the AMZ, excluding ENLK and ENLC, on the grant date for the Subject Award. The performance units would vest based on the percentile ranking of the average of ENLK's and ENLC's TSR achievement ("EnLink TSR") for the applicable performance period relative to the TSR achievement of the Peer Companies. As of the closing of the Merger, these performance-based Legacy ENLK Awards were modified, such that, the performance goal will, on a weighted average basis, (i) continue to relate to the EnLink TSR relative to the TSR performance of the Peer Companies in respect of periods preceding the effective time of the Merger; and (ii) relate solely to the TSR performance of ENLC relative to the TSR performance of such Peer Companies in respect of periods on and after the effective time of the Merger. At the end of the vesting period, recipients receive distribution equivalents, if any, with respect to the number of performance units vested. The vesting of performance units ranges from zero to 200% of the performance units granted depending on the extent to which the related performance goals are achieved over the relevant performance period.

The fair value of each performance unit was estimated as of the date of grant using a Monte Carlo simulation with the following assumptions used for all performance unit grants made under the plan: (i) a risk-free interest rate based on United States Treasury rates as of the grant date; (ii) a volatility assumption based on the historical realized price volatility of ENLK's common units and the designated Peer Companies' securities; (iii) an estimated ranking of ENLK and ENLC among the designated Peer Companies; and (iv) the distribution yield. The fair value of the performance unit on the date of grant is expensed over a vesting period of approximately three years.

The following table presents a summary of the performance units:

	Nine Months Ended September 30, 2019	
EnLink Midstream Partners, LP Performance Units:	**Number of Units**	**Weighted Average Grant-Date Fair Value**
Non-vested, beginning of period	451,669	$ 17.74
Vested (1)	(161,410)	10.54
Converted to ENLC (2)	(290,259)	28.31
Non-vested, end of period	—	$ —

(1) Vested units included 62,403 units withheld for payroll taxes paid on behalf of employees.

(2) As a result of the Merger, the performance-based Legacy ENLK Awards converted into ENLC unit-based performance awards using the 1.15 exchange ratio (as defined in the Merger Agreement) as the conversion rate.

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

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 nine months ended September 30, 2019 and 2018 is provided below (in millions). Since the Legacy ENLK Awards converted into ENLC unit-based awards as a result of the Merger, no additional performance units will vest as ENLK units under the GP Plan (such performance units, as converted, are eligible to vest as ENLC units) and no additional expense will be recognized after January 25, 2019 under the GP Plan.

	Three Months Ended September 30,		Nine Months Ended September 30,	
EnLink Midstream Partners, LP Performance Units:	**2019**	**2018**	**2019**	**2018**
Aggregate intrinsic value of units vested	$ —	$ 3.0	$ 2.1	$ 5.0
Fair value of units vested	$ —	$ 3.6	$ 1.7	$ 7.7

d. EnLink Midstream, LLC Restricted Incentive Units

ENLC restricted incentive units are valued at their fair value at the date of grant, which is equal to the market value of ENLC common units on such date. A summary of the restricted incentive unit activity for the nine months ended September 30, 2019 is provided below:

	Nine Months Ended September 30, 2019	
EnLink Midstream, LLC Restricted Incentive Units:	**Number of Units**	**Weighted Average Grant-Date Fair Value**
Non-vested, beginning of period	2,425,867	$ 14.62
Granted (1)	1,875,490	11.39
Vested (1)(2)	(1,632,100)	11.55
Forfeited	(488,913)	14.39
Converted from ENLK (3)	2,103,266	14.01
Non-vested, end of period	4,283,610	$ 14.10
Aggregate intrinsic value, end of period (in millions)	$ 36.4	

(1) Restricted incentive units typically vest at the end of three years. In March 2019, ENLC granted 420,842 restricted incentive units with a fair value of $4.8 million to officers and certain employees as bonus payments for 2018, and these restricted incentive units vested immediately and are included in the restricted incentive units granted and vested line items.
(2) Vested units included 563,606 units withheld for payroll taxes paid on behalf of employees.
(3) Represents Legacy ENLK Awards that were converted into ENLC unit-based awards using the 1.15 exchange ratio (as defined in the Merger Agreement) as the conversion rate.

A summary of the restricted incentive units' aggregate intrinsic value (market value at vesting date) and fair value of units vested (market value at date of grant) for the three and nine months ended September 30, 2019 and 2018 is provided below (in millions):

	Three Months Ended September 30,		Nine Months Ended September 30,	
EnLink Midstream, LLC Restricted Incentive Units:	**2019**	**2018**	**2019**	**2018**
Aggregate intrinsic value of units vested	$ 3.1	$ 3.3	$ 16.0	$ 12.6
Fair value of units vested	$ 5.8	$ 2.6	$ 18.9	$ 16.1

As of September 30, 2019, there was $29.1 million of unrecognized compensation cost related to non-vested ENLC restricted incentive units. The cost is expected to be recognized over a weighted-average period of 1.8 years.

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

e. EnLink Midstream, LLC's 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 units ranges from zero to 200% of the units granted depending on the extent to which the related performance goals are achieved over the relevant performance period.

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

The following table presents a summary of the performance units:

	Nine Months Ended September 30, 2019	
EnLink Midstream, LLC Performance Units:	**Number of Units**	**Weighted Average Grant-Date Fair Value**
Non-vested, beginning of period	418,149	$ 19.15
Granted	931,469	13.02
Vested (1)	(374,745)	21.08
Forfeited	(309,603)	15.28
Converted from ENLK (2)	333,798	25.84
Non-vested, end of period	999,068	$ 16.15
Aggregate intrinsic value, end of period (in millions)	$ 8.5	

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

A summary of the performance units' aggregate intrinsic value (market value at vesting date) and fair value of units vested (market value at date of grant) for the three and nine months ended September 30, 2019 and 2018 is provided below (in millions).

	Three Months Ended September 30,		Nine Months Ended September 30,	
EnLink Midstream, LLC Performance Units:	**2019**	**2018**	**2019**	**2018**
Aggregate intrinsic value of units vested	$ 1.6	$ 2.8	$ 3.4	$ 4.7
Fair value of units vested	$ 6.0	$ 3.5	$ 7.9	$ 7.7

As of September 30, 2019, there was $10.1 million of unrecognized compensation cost that related to non-vested ENLC performance units. That cost is expected to be recognized over a weighted-average period of 1.9 years.

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

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

2019 Performance Unit Awards

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

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

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

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

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

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

The fair value of each performance unit is estimated as of the date of grant using a Monte Carlo simulation with the following assumptions used for all performance unit grants made under the plan: (i) a risk-free interest rate based on United States Treasury rates as of the grant date; (ii) a volatility assumption based on the historical realized price volatility of ENLC's common units and the Designated Peer Companies' or Peer Companies' securities as applicable; (iii) an estimated ranking of ENLC (or for outstanding performance units granted prior to the Merger, ENLC and ENLK) among the Designated Peer Companies or Peer Companies, and (iv) the distribution yield. The fair value of the performance unit on the date of grant is expensed over a vesting period of approximately three years.

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

EnLink Midstream, LLC Performance Units:	June 2019	March 2019
Grant-Date Fair Value	$ 9.92	$ 13.10
Beginning TSR price	$ 9.84	$ 10.92
Risk-free interest rate	1.72 %	2.42 %
Volatility factor	33.50 %	33.86 %
Distribution yield	11.5 %	9.7 %

(10) Derivatives

Interest Rate Swaps

We periodically enter into interest rate swaps during the debt issuance process to hedge variability in future long-term debt interest payments that may result from changes in the benchmark interest rate (commonly the U.S. Treasury yield) prior to the debt being issued or to hedge variability in cash flows on our variable-rate debt. We designate interest rate swaps as cash flow hedges in accordance with ASC 815.

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

In May 2017, we entered into an interest rate swap in connection with the issuance of our 2047 Notes. Upon settlement of the interest rate swap in May 2017, we recorded the associated $2.2 million settlement loss in accumulated comprehensive loss on the consolidated balance sheets. We will amortize the settlement loss into interest expense on the consolidated statements of operations over the term of the 2047 Notes. There was no ineffectiveness related to the hedge.

For the three and nine months ended September 30, 2019, we recorded $1.8 million and $15.3 million, respectively, into accumulated other comprehensive loss related to changes in fair value of our interest rate swaps.

For the three and nine months ended September 30, 2019, we realized a gain of $0.1 million and $0.4 million, respectively, related to the monthly settlement of our interest rate swaps and an immaterial amount of amortization, which we recorded into interest expense, net of interest income from accumulated other comprehensive loss. For the three and nine months ended September 30, 2018, we recorded an immaterial amount into interest expense, net of interest income from accumulated other comprehensive loss. We expect to recognize $5.3 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):

	September 30, 2019
Fair value of derivative liabilities—current	$ (5.2)
Fair value of derivative liabilities—long-term	(10.2)
Net fair value of derivatives	$ (15.4)

Commodity Swaps

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2019	2018	2019	2018
Change in fair value of derivatives	$ (0.5)	$ (0.8)	$ 4.7	$ (14.8)
Realized gain (loss) on derivatives	8.0	(4.6)	11.5	(5.3)
Gain (loss) on derivative activity	$ 7.5	$ (5.4)	$ 16.2	$ (20.1)

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

	September 30, 2019	December 31, 2018
Fair value of derivative assets—current	$ 9.6	$ 28.6
Fair value of derivative assets—long-term	7.9	4.1
Fair value of derivative liabilities—current	(4.3)	(21.8)
Fair value of derivative liabilities—long-term	—	(2.4)
Net fair value of derivatives	$ 13.2	$ 8.5

Set forth below are the summarized notional volumes and fair values of all instruments held for price risk management purposes and related physical offsets at September 30, 2019 (in millions). The remaining term of the contracts extend no later than December 2022.

		September 30, 2019		
Commodity	**Instruments**	**Unit**	**Volume**	**Fair Value**
NGL (short contracts)	Swaps	Gallons	(39.7)	$ 2.5
NGL (long contracts)	Swaps	Gallons	8.8	(0.6)
Natural gas (short contracts)	Swaps	MMBtu	(4.7)	0.2
Natural gas (long contracts)	Swaps	MMBtu	1.9	0.1
Crude and condensate (short contracts)	Swaps	MMbbls	(12.0)	7.2
Crude and condensate (long contracts)	Swaps	MMbbls	1.6	3.8
Total fair value of derivatives				$ 13.2

On all transactions where we are exposed to counterparty risk, we analyze the counterparty's financial condition prior to entering into an agreement, establish limits, and monitor the appropriateness of these limits on an ongoing basis. We primarily deal with financial institutions when entering into financial derivatives on commodities. We have entered into Master ISDAs that allow for netting of swap contract receivables and payables in the event of default by either party. If our counterparties failed to perform under existing swap contracts, the maximum loss on our gross receivable position of $17.5 million as of September 30, 2019 would be reduced to $13.2 million due to the offsetting of gross fair value payables against gross fair value receivables as allowed by the ISDAs.

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

(11) Fair Value Measurements

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

	Level 2	
	September 30, 2019	December 31, 2018
Interest rate swaps (1)	$ (15.4)	$ —
Commodity swaps (2)	$ 13.2	$ 8.5

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

Fair Value of Financial Instruments

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

	September 30, 2019		December 31, 2018	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Long-term debt (1)	$ 4,576.8	$ 4,264.3	$ 4,319.6	$ 3,953.6
Secured term loan receivable (2)	$ —	$ —	$ 51.1	$ 51.1

(1) The carrying value of long-term debt as of December 31, 2018 includes current maturities. The carrying value of long-term debt is reduced by debt issuance costs of $ 30.8 million and $24.3 million at September 30, 2019 and December 31, 2018, respectively. The respective fair values do not factor in debt issuance costs.
(2) In late May 2019, White Star, the counterparty to our $58.0 million second lien secured term loan receivable, filed for reorganization under Chapter 11 of the U.S. Bankruptcy Code. We do not believe that it is probable that White Star will be able to repay the outstanding amounts owed to us under the second lien secured term loan. For additional information regarding this transaction, refer to "Note 2—Significant Accounting Policies."

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

As of September 30, 2019, ENLC had total borrowings under senior unsecured notes of $500.0 million maturing in 2029 with a fixed interest rate of 5.375%. As of September 30, 2019, we had total borrowings under senior unsecured notes of $3.1 billion maturing between 2024 and 2047 with fixed interest rates ranging from 4.15% to 5.60%. As of December 31, 2018, we had total borrowings under senior unsecured notes of $3.5 billion maturing between 2019 and 2047 with fixed interest rates ranging from 2.70% to 5.60%.

The fair values of all senior unsecured notes as of September 30, 2019 and December 31, 2018 were based on Level 2 inputs from third-party market quotations. The fair values of the secured term loan receivable were calculated using Level 2 inputs from third-party banks.

(12) Segment Information

Effective January 1, 2019, we changed our reportable operating segments to reflect how we currently make financial decisions and allocate resources. As of December 31, 2018, our reportable operating segments consisted of the following: (i) natural gas gathering, processing, transmission, and fractionation operations located in north Texas and the Permian Basin primarily in west Texas, (ii) natural gas pipelines, processing plants, storage facilities, NGL pipelines, and fractionation assets in Louisiana, (iii) natural gas gathering and processing operations located throughout Oklahoma, and (iv) crude rail, truck, pipeline, and barge facilities in west Texas, south Texas, Louisiana, Oklahoma, and ORV. Effective January 1, 2019, we are reporting financial performance in five segments: Permian, North Texas, Oklahoma, Louisiana, and Corporate. Crude and condensate operations are combined regionally with natural gas and NGL operations in the Oklahoma and Permian segments, and ORV operations are included in the Louisiana segment. We have recast the segment information for the three and nine months ended September 30, 2018 to conform to the current period presentation.

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

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

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

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

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

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

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

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

	Permian	North Texas	Oklahoma	Louisiana	Corporate	Totals
Three Months Ended September 30, 2019						
Natural gas sales	$ 24.3	$ 22.2	$ 54.6	$ 92.0	$ —	$ 193.1
NGL sales	0.3	6.0	4.6	421.0	—	431.9
Crude oil and condensate sales	409.4	—	28.2	74.6	—	512.2
Product sales	434.0	28.2	87.4	587.6	—	1,137.2
Natural gas sales—related parties	(0.1)	—	—	—	0.1	—
NGL sales—related parties	69.3	21.0	90.2	7.9	(188.4)	—
Crude oil and condensate sales—related parties	2.8	1.1	—	1.7	(5.6)	—
Product sales—related parties	72.0	22.1	90.2	9.6	(193.9)	—
Gathering and transportation	14.7	50.1	63.7	12.2	—	140.7
Processing	8.3	36.3	35.7	0.8	—	81.1
NGL services	—	—	—	11.2	—	11.2
Crude services	6.4	—	5.9	13.5	—	25.8
Other services	4.0	0.3	0.1	0.1	—	4.5
Midstream services	33.4	86.7	105.4	37.8	—	263.3
NGL services—related parties	—	—	—	—	—	—
Crude services—related parties	—	—	0.2	—	(0.2)	—
Midstream services—related parties	—	—	0.2	—	(0.2)	—
Revenue from contracts with customers	539.4	137.0	283.2	635.0	(194.1)	1,400.5
Cost of sales	(474.2)	(41.4)	(148.4)	(529.6)	194.1	(999.5)
Operating expenses	(28.9)	(26.2)	(25.7)	(38.4)	—	(119.2)
Gain on derivative activity	—	—	—	—	7.5	7.5
Segment profit	$ 36.3	$ 69.4	$ 109.1	$ 67.0	$ 7.5	$ 289.3
Depreciation and amortization	$ (31.6)	$ (35.4)	$ (51.1)	$ (37.3)	$ (1.9)	$ (157.3)
Goodwill	$ —	$ —	$ 190.3	$ —	$ —	$ 190.3
Capital expenditures	$ 119.7	$ 5.0	$ 48.6	$ 21.5	$ 1.7	$ 196.5

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

	Permian	North Texas	Oklahoma	Louisiana	Corporate	Totals
Three Months Ended September 30, 2018						
Natural gas sales	$ 39.6	$ 29.5	$ 41.9	$ 129.5	$ —	$ 240.5
NGL sales	0.1	16.8	12.8	839.6	—	869.3
Crude oil and condensate sales	636.4	0.5	18.6	66.9	—	722.4
Product sales	676.1	46.8	73.3	1,036.0	—	1,832.2
Natural gas sales—related parties	—	—	0.1	—	—	0.1
NGL sales—related parties	138.6	15.2	192.5	10.9	(347.2)	10.0
Crude oil and condensate sales—related parties	(0.5)	0.5	(0.4)	—	0.5	0.1
Product sales—related parties	138.1	15.7	192.2	10.9	(346.7)	10.2
Gathering and transportation	8.2	57.6	44.6	17.5	—	127.9
Processing	6.5	39.6	37.1	0.8	—	84.0
NGL services	—	—	—	11.9	—	11.9
Crude services	(1.1)	—	0.9	15.3	—	15.1
Other services	2.1	0.3	—	0.2	—	2.6
Midstream services	15.7	97.5	82.6	45.7	—	241.5
Gathering and transportation—related parties	—	8.7	7.2	—	—	15.9
Processing—related parties	—	10.1	3.3	—	—	13.4
Crude services—related parties	6.3	—	0.1	—	—	6.4
Other services—related parties	—	0.1	—	—	—	0.1
Midstream services—related parties	6.3	18.9	10.6	—	—	35.8
Revenue from contracts with customers	836.2	178.9	358.7	1,092.6	(346.7)	2,119.7
Cost of sales	(775.3)	(56.0)	(228.2)	(983.8)	346.7	(1,696.6)
Operating expenses	(22.4)	(27.9)	(23.0)	(41.4)	—	(114.7)
Loss on derivative activity	—	—	—	—	(5.4)	(5.4)
Segment profit	$ 38.5	$ 95.0	$ 107.5	$ 67.4	$ (5.4)	$ 303.0
Depreciation and amortization	$ (27.9)	$ (31.9)	$ (44.8)	$ (39.7)	$ (2.4)	$ (146.7)
Impairments	$ —	$ —	$ —	$ (24.6)	$ —	$ (24.6)
Goodwill	$ 29.3	$ 202.7	$ 190.3	$ —	$ —	$ 422.3
Capital expenditures	$ 91.6	$ 8.1	$ 138.9	$ 13.7	$ 1.0	$ 253.3

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

	Permian	North Texas	Oklahoma	Louisiana	Corporate	Totals
Nine Months Ended September 30, 2019						
Natural gas sales	$ 59.4	$ 104.7	$ 176.5	$ 316.8	$ —	$ 657.4
NGL sales	0.9	24.0	17.8	1,492.9	—	1,535.6
Crude oil and condensate sales	1,622.2	—	86.4	216.9	—	1,925.5
Product sales	1,682.5	128.7	280.7	2,026.6	—	4,118.5
Natural gas sales—related parties	0.3	0.3	—	—	(0.6)	—
NGL sales—related parties	242.9	71.7	320.9	16.4	(651.9)	—
Crude oil and condensate sales—related parties	13.7	3.8	—	1.7	(19.2)	—
Product sales—related parties	256.9	75.8	320.9	18.1	(671.7)	—
Gathering and transportation	36.3	149.0	178.2	46.1	—	409.6
Processing	23.3	106.8	105.5	2.5	—	238.1
NGL services	—	—	—	32.9	—	32.9
Crude services	16.9	—	15.1	40.2	—	72.2
Other services	8.4	0.8	—	0.5	—	9.7
Midstream services	84.9	256.6	298.8	122.2	—	762.5
NGL services—related parties	—	—	—	(3.3)	3.3	—
Crude services—related parties	—	—	1.7	—	(1.7)	—
Midstream services—related parties	—	—	1.7	(3.3)	1.6	—
Revenue from contracts with customers	2,024.3	461.1	902.1	2,163.6	(670.1)	4,881.0
Cost of sales	(1,830.9)	(166.1)	(492.0)	(1,844.1)	670.1	(3,663.0)
Operating expenses	(85.1)	(77.7)	(77.2)	(111.6)	—	(351.6)
Gain on derivative activity	—	—	—	—	16.2	16.2
Segment profit	$ 108.3	$ 217.3	$ 332.9	$ 207.9	$ 16.2	$ 882.6
Depreciation and amortization	$ (89.6)	$ (106.6)	$ (144.8)	$ (116.0)	$ (6.1)	$ (463.1)
Goodwill	$ —	$ —	$ 190.3	$ —	$ —	$ 190.3
Capital expenditures	$ 268.0	$ 36.3	$ 227.1	$ 82.0	$ 5.7	$ 619.1

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

	Permian	North Texas	Oklahoma	Louisiana	Corporate	Totals
Nine Months Ended September 30, 2018						
Natural gas sales	$ 110.8	$ 98.1	$ 127.9	$ 377.2	$ —	$ 714.0
NGL sales	0.9	16.8	18.3	2,075.9	—	2,111.9
Crude oil and condensate sales	1,725.1	0.5	63.8	151.2	—	1,940.6
Product sales	1,836.8	115.4	210.0	2,604.3	—	4,766.5
Natural gas sales—related parties	—	—	2.5	—	—	2.5
NGL sales—related parties	345.4	35.7	433.0	45.4	(822.1)	37.4
Crude oil and condensate sales—related parties	1.4	1.3	0.3	0.2	(2.1)	1.1
Product sales—related parties	346.8	37.0	435.8	45.6	(824.2)	41.0
Gathering and transportation	22.0	72.2	85.8	51.8	—	231.8
Processing	17.6	41.8	93.5	2.5	—	155.4
NGL services	—	—	—	38.8	—	38.8
Crude services	(1.0)	—	1.0	43.0	—	43.0
Other services	5.8	0.6	—	0.7	—	7.1
Midstream services	44.4	114.6	180.3	136.8	—	476.1
Gathering and transportation—related parties	—	122.7	80.6	—	—	203.3
Processing—related parties	—	108.5	48.5	—	—	157.0
Crude services—related parties	14.9	—	1.5	—	—	16.4
Other services—related parties	—	0.5	—	—	—	0.5
Midstream services—related parties	14.9	231.7	130.6	—	—	377.2
Revenue from contracts with customers	2,242.9	498.7	956.7	2,786.7	(824.2)	5,660.8
Cost of sales	(2,083.3)	(137.9)	(537.6)	(2,469.1)	824.2	(4,403.7)
Operating expenses	(70.9)	(84.7)	(64.5)	(117.2)	—	(337.3)
Loss on derivative activity	—	—	—	—	(20.1)	(20.1)
Segment profit	$ 88.7	$ 276.1	$ 354.6	$ 200.4	$ (20.1)	$ 899.7
Depreciation and amortization	$ (82.0)	$ (94.8)	$ (133.3)	$ (113.0)	$ (7.0)	$ (430.1)
Impairments	$ —	$ —	$ —	$ (24.6)	$ —	$ (24.6)
Goodwill	$ 29.3	$ 202.7	$ 190.3	$ —	$ —	$ 422.3
Capital expenditures	$ 208.0	$ 16.1	$ 382.8	$ 42.5	$ 3.3	$ 652.7

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2019	2018	2019	2018
Segment profit	$ 289.3	$ 303.0	$ 882.6	$ 899.7
General and administrative expenses	(38.3)	(39.2)	(108.8)	(94.5)
Gain (loss) on disposition of assets	3.0	—	2.9	(1.3)
Depreciation and amortization	(157.3)	(146.7)	(463.1)	(430.1)
Impairments	—	(24.6)	—	(24.6)
Loss on secured term loan receivable	—	—	(52.9)	—
Operating income	$ 96.7	$ 92.5	$ 260.7	$ 349.2

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

The table below represents information about segment assets as of September 30, 2019 and December 31, 2018 (in millions):

Segment Identifiable Assets:	**September 30, 2019**	**December 31, 2018**
Permian	$ 2,239.4	$ 2,096.8
North Texas	1,191.2	1,308.2
Oklahoma	3,262.9	3,209.5
Louisiana	2,570.8	2,734.5
Corporate	152.5	222.3
Total identifiable assets	$ 9,416.8	$ 9,571.3

(13) 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:	**September 30, 2019**	**December 31, 2018**
Natural gas and NGLs inventory	$ 49.8	$ 41.3
Secured term loan receivable from contract restructuring, net of discount of $1.1 at December 31, 2018 (1)	—	19.4
Prepaid expenses and other	17.7	12.1
Natural gas and NGLs inventory, prepaid expenses, and other	$ 67.5	$ 72.8

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

Other current liabilities:	**September 30, 2019**	**December 31, 2018**
Accrued interest	$ 57.8	$ 37.3
Accrued wages and benefits, including taxes	22.8	37.2
Accrued ad valorem taxes	34.8	28.1
Capital expenditure accruals	74.8	50.6
Onerous performance obligations	—	9.0
Short-term lease liability	21.3	1.5
Suspense producer payments	16.8	34.6
Operating expense accruals	9.2	10.2
Other	29.5	38.2
Other current liabilities	$ 267.0	$ 246.7

Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations

Please read the following discussion of our financial condition and results of operations in conjunction with the financial statements and notes thereto included elsewhere in this report. In addition, please refer to the Definitions page set forth in this report prior to Part I—Financial Information.

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

Overview

We are a Delaware limited partnership formed on July 12, 2002. We primarily focus on providing midstream energy services, including:

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

Our midstream energy asset network includes approximately 12,000 miles of pipelines, 21 natural gas processing plants with approximately 5.3 Bcf/d of processing capacity, seven fractionators with approximately 280,000 Bbls/d of fractionation capacity, barge and rail terminals, product storage facilities, purchasing and marketing capabilities, brine disposal wells, a crude oil trucking fleet, and equity investments in certain joint ventures. We manage and report our activities primarily according to the nature of activity and geography. We have five reportable segments:

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

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

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

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

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

We manage our operations by focusing on gross operating margin because our business is generally to gather, process, transport, or market natural gas, NGLs, crude oil, and condensate using our assets for a fee. We earn our fees through various fee-based contractual arrangements, which include stated fee-only contract arrangements or arrangements with fee-based components where we purchase and resell commodities in connection with providing the related service and earn a net margin as our fee. We earn our net margin under our purchase and resell contract arrangements primarily as a result of stated service-related fees that are deducted from the price of the commodity purchase. While our transactions vary in form, the essential element of most of our transactions is the use of our assets to transport a product or provide a processed product to an end-user or marketer at the tailgate of the plant, pipeline, or barge, truck, or rail terminal. We define gross operating margin as operating revenue minus cost of sales. Gross operating margin is a non-GAAP financial measure and is explained in greater detail under "Non-GAAP Financial Measures" below. Approximately 90% of our gross operating margin was derived from fee-based contractual arrangements with minimal direct commodity price exposure for the nine months ended September 30, 2019. We reflect revenue as "Product sales" and "Midstream services" on the consolidated statements of operations.

Devon is one of our primary customers. For the three and nine months ended September 30, 2019, approximately 31.8% and 30.2% of our gross operating margin, respectively, was attributable to commercial contracts with Devon. For the three and nine months ended September 30, 2018, approximately 38.5% and 38.3% of our gross operating margin, respectively, was attributable to commercial contracts with Devon.

Our revenues and gross operating 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.

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

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

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

We realize gross operating margins from our gathering and processing services primarily through different contractual arrangements: processing margin (“margin”) contracts, POL contracts, POP contracts, fixed-fee component contracts, or a combination of these contractual arrangements. “See Item 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 gross operating margins are higher during periods of high NGL prices relative to natural gas prices. Gross operating margin results under POL contracts are impacted only by the value of the liquids produced with margins higher during periods of higher liquids prices. Gross operating margin results under POP contracts are impacted only by the value of the natural gas and liquids produced with margins higher during periods of higher natural gas and liquids prices. Under fixed-fee based contracts, our gross operating margins are driven by throughput volume.

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

General and administrative expenses are dictated by the terms of our partnership agreement. These expenses include the costs of employee, officer, and director compensation and benefits properly allocable to us, fees, services, and other transaction costs related to acquisitions, and all other expenses necessary or appropriate to the conduct of business and allocable to us. Our partnership agreement provides that our general partner determines the expenses that are allocable to us in any reasonable manner determined by our general partner in its sole discretion. Subsequent to the Merger, ENLK no longer allocates general and administrative expenses to ENLC.

Recent Developments

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

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

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

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

Riptide Processing Plant. In September 2019, we completed construction of a 65 MMcf/d expansion to our Riptide processing plant in the Midland Basin, bringing the total operational processing capacity at the plant to 165 MMcf/d.

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

Non-GAAP Financial Measures

Gross Operating Margin

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

The following table provides a reconciliation of operating income to gross operating margin (in millions):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2019	2018	2019	2018
Operating income	$ 96.7	$ 92.5	$ 260.7	$ 349.2
Add:				
Operating expenses	119.2	114.7	351.6	337.3
General and administrative expenses	38.3	39.2	108.8	94.5
(Gain) loss on disposition of assets	(3.0)	—	(2.9)	1.3
Depreciation and amortization	157.3	146.7	463.1	430.1
Impairments	—	24.6	—	24.6
Loss on secured term loan receivable	—	—	52.9	—
Gross operating margin	$ 408.5	$ 417.7	$ 1,234.2	$ 1,237.0

Results of Operations

The table below sets forth certain financial and operating data for the periods indicated. We manage our operations by focusing on gross operating margin, which we define as revenue less cost of sales as reflected in the table below (in millions, except volumes):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2019	2018	2019	2018
Permian Segment				
Revenues	$ 539.4	$ 836.2	$ 2,024.3	$ 2,242.9
Cost of sales	(474.2)	(775.3)	(1,830.9)	(2,083.3)
Total gross operating margin	$ 65.2	$ 60.9	$ 193.4	$ 159.6
North Texas Segment				
Revenues	$ 137.0	$ 178.9	$ 461.1	$ 498.7
Cost of sales	(41.4)	(56.0)	(166.1)	(137.9)
Total gross operating margin	$ 95.6	$ 122.9	$ 295.0	$ 360.8
Oklahoma Segment				
Revenues	$ 283.2	$ 358.7	$ 902.1	$ 956.7
Cost of sales	(148.4)	(228.2)	(492.0)	(537.6)
Total gross operating margin	$ 134.8	$ 130.5	$ 410.1	$ 419.1
Louisiana Segment				
Revenues	$ 635.0	$ 1,092.6	$ 2,163.6	$ 2,786.7
Cost of sales	(529.6)	(983.8)	(1,844.1)	(2,469.1)
Total gross operating margin	$ 105.4	$ 108.8	$ 319.5	$ 317.6
Corporate Segment				
Revenues	$ (186.6)	$ (352.1)	$ (653.9)	$ (844.3)
Cost of sales	194.1	346.7	670.1	824.2
Total gross operating margin	$ 7.5	$ (5.4)	$ 16.2	$ (20.1)
Total				
Revenues	$ 1,408.0	$ 2,114.3	$ 4,897.2	$ 5,640.7
Cost of sales	(999.5)	(1,696.6)	(3,663.0)	(4,403.7)
Total gross operating margin	$ 408.5	$ 417.7	$ 1,234.2	$ 1,237.0
Midstream Volumes:				
Permian Segment				
Gathering and Transportation (MMBtu/d)	751,400	557,100	695,300	498,000
Processing (MMBtu/d)	798,200	566,200	745,100	512,900
Crude Oil Handling (Bbls/d)	112,900	131,700	135,000	119,900
North Texas Segment				
Gathering and Transportation (MMBtu/d)	1,644,300	1,710,200	1,658,000	1,741,100
Processing (MMBtu/d)	760,700	744,600	753,600	750,200
Oklahoma Segment				
Gathering and Transportation (MMBtu/d)	1,351,800	1,259,700	1,304,100	1,181,800
Processing (MMBtu/d)	1,323,100	1,239,000	1,284,800	1,170,300
Crude Oil Handling (Bbls/d)	59,600	17,400	47,600	12,900
Louisiana Segment				
Gathering and Transportation (MMBtu/d)	2,078,500	2,273,700	2,025,000	2,197,100
Processing (MMBtu/d)	385,500	429,200	396,600	422,200
Crude Oil Handling (Bbls/d)	21,200	17,200	18,800	14,800
NGL Fractionation (Gals/d)	7,240,100	6,545,100	7,231,400	6,457,000
Brine Disposal (Bbls/d)	2,500	3,300	3,100	3,200

Three Months Ended September 30, 2019 Compared to Three Months Ended September 30, 2018

Gross Operating Margin. Gross operating margin was $408.5 million for the three months ended September 30, 2019 compared to $417.7 million for the three months ended September 30, 2018, a decrease of $9.2 million, or 2.2%, due to the following:

- *Permian Segment.* Gross operating margin in the Permian segment increased $4.3 million, which was primarily due to a $9.5 million increase in gross operating margin due to higher volumes from our Permian gas assets related to continued development by our customers, as a result of $5.2 million from our Delaware Basin assets and $4.3 million from our Midland Basin assets. These increases were partially offset by a $5.5 million decrease from our Permian crude assets, which was attributable to a $2.1 million decrease in gross operating margin due to lower crude oil handling volumes and the expiration of an MVC related to a transportation services agreement with Devon during the third quarter of 2019 and a $3.4 million decrease in gross operating margin associated with our physical crude marketing arrangements. We manage our exposure to crude price fluctuations in our physical crude marketing arrangements through various derivative arrangements. The timing of our realization of the gains or losses from these crude derivative arrangements may not occur in the same period as the corresponding physical crude marketing transaction, and all associated gains and losses from the derivative arrangements are reflected in our Corporate segment.

- *North Texas Segment.* Gross operating margin in the North Texas segment decreased $27.3 million primarily due to the January 1, 2019 expiration of Devon's obligations related to MVCs on our North Texas assets and volume declines due to limited new drilling. Shortfall revenue from the Devon-related MVCs was $22.1 million for the three months ended September 30, 2018.

- *Oklahoma Segment.* Gross operating margin in the Oklahoma segment increased $4.3 million, which was primarily due to higher volumes from our Oklahoma crude assets. Gross operating margin from our Oklahoma gas assets decreased by $3.0 million between periods as increases in gross operating margin from higher volumes were offset by the negative impact of NGL and gas price declines under our Oklahoma processing contracts with fixed recovery provisions.

- *Louisiana Segment.* Gross operating margin in the Louisiana segment decreased $3.4 million. Gross operating margin from our NGL transmission and fractionation assets increased by $9.0 million, which was primarily due to higher volumes that resulted from the completion of the Cajun-Sibon pipeline expansion in April 2019. The increase was offset by a $12.4 million decrease from our Louisiana gas business. Gross operating margin from our Louisiana gas transmission assets decreased $6.0 million due to the expiration of certain firm transportation contracts and decreased volumes. Gross operating margin from our Louisiana gas plants decreased $6.4 million due to lower processing margins and volumes attributable to a less favorable processing environment during the three months ended September 30, 2019.

- *Corporate Segment.* Gross operating margin in the Corporate segment increased $12.9 million, which was primarily due to the changes in fair value of our commodity swaps between the periods as summarized below (in millions):

	Three Months Ended September 30,	
	2019	2018
Realized swaps:		
Crude swaps	$ 5.5	$ 0.9
NGL swaps	1.8	(4.0)
Gas swaps	0.7	(1.5)
Realized gain (loss) on derivatives	8.0	(4.6)
Unrealized swaps:		
Crude swaps	(0.4)	1.3
NGL swaps	(0.4)	(2.0)
Gas swaps	0.3	(0.1)
Change in fair value of derivatives	(0.5)	(0.8)
Gain (loss) on derivative activity	$ 7.5	$ (5.4)

Certain gathering and processing agreements provide for quarterly or annual MVCs, including MVCs from Devon. Under these agreements, our customers agree to ship and/or process a minimum volume of commodity on our systems over an agreed time period. If a customer under such an agreement fails to meet its MVC for a specified period, the customer is obligated to pay a contractually-determined fee based upon the shortfall between actual commodity volumes and the MVC for that period. Some of these agreements also contain make-up right provisions that allow a customer to utilize gathering or processing fees in excess of the MVC in subsequent periods to offset shortfall amounts in previous periods. We record revenue under MVC contracts during periods of shortfall when it is known that the customer cannot, or will not, make up the deficiency in subsequent periods.

Revenue recorded for the shortfall between actual production volumes and the MVC is as follows (in millions):

	Permian	North Texas	Oklahoma	Total
Three Months Ended				
September 30, 2019				
Midstream services	$ 1.7	$ —	$ 4.8	$ 6.5
Total	$ 1.7	$ —	$ 4.8	$ 6.5
September 30, 2018				
Midstream services	$ 2.1	$ 17.7	$ —	$ 19.8
Midstream services—related parties	0.6	4.4	—	5.0
Total	$ 2.7	$ 22.1	$ —	$ 24.8

On January 1, 2019, certain MVCs related to gathering and processing agreements with Devon for operations in the North Texas and Oklahoma segments expired. These MVCs generated $22.1 million in shortfall revenue for the three months ended September 30, 2018. Additionally, an MVC related to a transportation services agreement with Devon for operations in the Permian segment expired on July 31, 2019. This MVC generated $1.7 million and $2.7 million in shortfall revenue for the three months ended September 30, 2019 and 2018, respectively. Our MVC revenue in the Oklahoma segment is generated from a gathering and processing arrangement with Devon which expires in 2030, with the MVC provision under the agreement expiring in December 2020.

Operating Expenses. Operating expenses were $119.2 million for the three months ended September 30, 2019 compared to $114.7 million for the three months ended September 30, 2018, an increase of $4.5 million, or 3.9%. The primary contributors to the total increase by segment were as follows (in millions):

	Three Months Ended September 30,		Change	
	2019	2018	$	%
Permian Segment	$ 28.9	$ 22.4	$ 6.5	29.0 %
North Texas Segment	26.2	27.9	(1.7)	(6.1)%
Oklahoma Segment	25.7	23.0	2.7	11.7 %
Louisiana Segment	38.4	41.4	(3.0)	(7.2)%
Total	$ 119.2	$ 114.7	$ 4.5	3.9 %

- *Permian Segment.* Operating expenses in the Permian segment increased $6.5 million primarily due to expanded operations with increases in utilities, materials and supplies expenses, construction fees and services, and ad valorem taxes.
- *North Texas Segment.* Operating expenses in the North Texas segment decreased $1.7 million primarily due to reduced compression and treater rental costs.
- *Oklahoma Segment.* Operating expenses in the Oklahoma segment increased $2.7 million primarily due to expanded operations with increases in compressor rentals, compression operations and maintenance, and labor and benefits costs.
- *Louisiana Segment.* Operating expenses in the Louisiana segment decreased $3.0 million primarily due to reduced compression rental expense and lower ad valorem taxes.

Depreciation and Amortization. Depreciation and amortization was $157.3 million for the three months ended September 30, 2019 compared to $146.7 million for the three months ended September 30, 2018, an increase of $10.6 million, or 7.2%. This increase was primarily due to additional depreciation of $6.8 million attributable to new assets placed in service in key growth areas, primarily related to the completion of the Thunderbird Plant, the expansion of the Lobo III cryogenic gas processing plant, further expansion of Avenger, and additional well connections in Oklahoma.

Impairments. For the three months ended September 30, 2018, we recognized impairments of property and equipment of $24.6 million related to certain non-core pipeline assets because the carrying values were no longer recoverable.

Interest Expense. Interest expense was $56.6 million for the three months ended September 30, 2019 compared to $44.1 million for the three months ended September 30, 2018, an increase of $12.5 million, or 28.3%. Interest expense consisted of the following (in millions):

	Three Months Ended September 30,	
	2019	2018
Senior Notes	$ 37.3	$ 40.0
ENLK Credit Facility	—	6.9
Related party debt	18.7	—
Capitalized interest	(0.3)	(2.3)
Amortization of debt issue costs and net discounts (premiums)	1.1	0.8
Other	(0.2)	(1.3)
Total	$ 56.6	$ 44.1

Nine Months Ended September 30, 2019 Compared to Nine Months Ended September 30, 2018

Gross Operating Margin. Gross operating margin was $1,234.2 million for the nine months ended September 30, 2019 compared to $1,237.0 million for the nine months ended September 30, 2018, a decrease of $2.8 million, or 0.2%, due to the following:

- *Permian Segment.* Gross operating margin in the Permian segment increased $33.8 million, which was primarily due to a $34.8 million increase in gross operating margin due to higher volumes on our Permian gas assets from continued development by our customers, including $20.0 million from our Delaware Basin assets, and $14.8 million from our Midland Basin assets. This increase was slightly offset by a $1.3 million decrease in gross operating margin from our Permian crude assets, which was due to a $3.9 million increase in gross operating margin from our Midland and Delaware Basins crude assets, offset by a $5.2 million decrease in gross operating margin from our south Texas assets due to an MVC expiration in July 2019 and decreased crude activity during 2019.

- *North Texas Segment.* Gross operating margin in the North Texas segment decreased $65.8 million, which was primarily due to the January 1, 2019 expiration of Devon's obligations related to MVCs on our North Texas assets and normal volume declines due to limited new drilling. Shortfall revenue from the Devon-related MVCs was $61.1 million for the nine months ended September 30, 2018.

- *Oklahoma Segment.* Gross operating margin in the Oklahoma segment decreased $9.0 million. Gross operating margin from our Oklahoma assets increased $36.1 million, which was primarily due to higher volumes from continued development by our customers, with $18.6 million contributed by our Oklahoma gas assets and $17.5 million contributed by our Oklahoma crude assets. This increase in gross operating margin was offset by the recognition of $45.5 million in gross operating margin from a contract restructuring with White Star during the nine months ended September 30, 2018.

- *Louisiana Segment.* Gross operating margin in the Louisiana segment increased $1.9 million. Gross operating margin from our NGL assets increased by $17.4 million primarily due to higher volumes with the completion of the Cajun-Sibon pipeline expansion in April 2019. Our ORV crude assets contributed an increase of $4.3 million primarily due to higher volumes. These increases were partially offset by a decrease of $19.2 million from our Louisiana gas business, primarily due to a $11.2 million decrease from our Louisiana gas plants due to a less favorable processing environment during the nine months ended September 30, 2019 and an $8.0 million decrease from our Louisiana gas transportation assets due to the expiration of certain firm transportation contracts and decreased volumes during the same period.

- *Corporate Segment.* Gross operating margin in the Corporate segment increased $36.3 million, which was primarily due to the changes in fair value of our commodity swaps between the periods as summarized below (in millions):

	Nine Months Ended September 30,	
	2019	2018
Realized swaps:		
Crude swaps	$ 6.4	$ 0.8
NGL swaps	7.4	(6.7)
Gas swaps	(2.3)	0.6
Realized gain (loss) on derivatives	11.5	(5.3)
Unrealized swaps:		
Crude swaps	4.1	(6.5)
NGL swaps	(2.7)	(5.1)
Gas swaps	3.3	(3.2)
Change in fair value of derivatives	4.7	(14.8)
Gain (loss) on derivative activity	$ 16.2	$ (20.1)

Revenue recorded for the shortfall between actual production volumes and the MVC is as follows (in millions):

	Permian	North Texas	Oklahoma	Total
Nine Months Ended				
September 30, 2019				
Midstream services	$ 9.4	$ —	$ 4.8	$ 14.2
Total	$ 9.4	$ —	$ 4.8	$ 14.2
September 30, 2018				
Midstream Services (1)	$ 2.1	$ 17.8	$ 52.7	$ 72.6
Midstream services—related parties	6.3	43.3	1.2	50.8
Total	$ 8.4	$ 61.1	$ 53.9	$ 123.4

(1) We restructured a natural gas gathering and processing contract with White Star that contained MVCs. As a result, we recognized $45.5 million of midstream services revenue in the Oklahoma segment for the nine months ended September 30, 2018.

On January 1, 2019, certain MVCs related to gathering and processing agreements with Devon for operations in the North Texas and Oklahoma segments expired. These MVCs generated $62.3 million in shortfall revenue for the nine months ended September 30, 2018. Additionally, an MVC related to a transportation services agreement with Devon for operations in the Permian segment expired on July 31, 2019. This MVC generated $9.4 million and $8.4 million in shortfall revenue for the nine months ended September 30, 2019 and 2018, respectively. Our MVC revenue in the Oklahoma segment is generated from a gathering and processing arrangement with Devon which expires in 2030, with the MVC provision under the agreement expiring in December 2020.

Operating Expenses. Operating expenses were $351.6 million for the nine months ended September 30, 2019 compared to $337.3 million for the nine months ended September 30, 2018, an increase of $14.3 million, or 4.2%. The primary contributors to the increase by segment were as follows (in millions):

	Nine Months Ended September 30,		Change	
	2019	2018	$	%
Permian Segment	$ 85.1	$ 70.9	$ 14.2	20.0 %
North Texas Segment	77.7	84.7	(7.0)	(8.3)%
Oklahoma Segment	77.2	64.5	12.7	19.7 %
Louisiana Segment	111.6	117.2	(5.6)	(4.8)%
Total	$ 351.6	$ 337.3	$ 14.3	4.2 %

- *Permian Segment.* Operating expenses in the Permian segment increased $14.2 million primarily due to expanded operations and higher utilities expense, bulk purchases of materials and supplies, construction fees and services, and compressor rentals.

- *North Texas Segment.* Operating expenses in the North Texas segment decreased $7.0 million primarily due to decreased compressor rentals, compressor overhauls, and labor and benefits costs.

- *Oklahoma Segment.* Operating expenses in the Oklahoma segment increased $12.7 million primarily due to expanded operations with increases in utilities, equipment rentals, compression operations and maintenance, and labor and benefits costs.

- *Louisiana Segment.* Operating expenses in the Louisiana segment decreased $5.6 million primarily due to reduced materials and supplies expenses, labor and benefits costs, and compression rentals partially offset by increased equipment rental and utility costs.

General and Administrative Expenses. General and administrative expenses were $108.8 million for the nine months ended September 30, 2019 compared to $94.5 million for the nine months ended September 30, 2018, an increase of $14.3 million, or 15.1%. The primary contributors to the increase were as follows:

- Transaction costs increased $0.9 million, which was primarily due to costs incurred related to the Merger, which closed during the first quarter of 2019.

- Unit-based compensation expense increased $4.4 million, which was primarily due to increased bonus expense and accelerated vesting related to an executive departure in the third quarter of 2019. This increase was partially offset by accelerated vesting related to the GIP Transaction and an organizational realignment in the third quarter of 2018.

- Fees and services expense increased $3.8 million, which was primarily due to increased software consulting and legal fees.

- Salaries and wages expense increased $1.2 million, which was primarily due to severance expense for an executive departure in the third quarter of 2019.

Depreciation and Amortization. Depreciation and amortization was $463.1 million for the nine months ended September 30, 2019 compared to $430.1 million for the nine months ended September 30, 2018, an increase of $33.0 million, or 7.7%. This increase was primarily due to increased depreciation of $19.0 million attributable to new assets placed in service in key growth areas, primarily related to the completion of the Thunderbird Plant, the expansion of the Lobo III cryogenic gas processing plant, the Cajun-Sibon NGL pipeline, Avenger, the Black Coyote crude oil gathering system, and well connections in Oklahoma. Additionally, depreciation increased by $16.2 million primarily due to retirements and reductions in our estimated useful lives of certain assets primarily located in the Texas and Louisiana segments. These increases were partially offset by a $7.8 million decrease due to a reduction in depreciation resulting from an impairment of the carrying value of certain non-core crude pipeline assets during 2018.

Impairments. For the nine months ended September 30, 2018, we recognized impairments of property and equipment of $24.6 million related to certain non-core pipeline assets because the carrying values were no longer recoverable.

Loss on secured term loan receivable. We have recorded a $52.9 million loss in our consolidated statement of operations for the nine months ended September 30, 2019 related to the write-off of the secured term loan receivable. For additional information regarding this transaction, refer to “Item 1. Financial Statements—Note 2.”

Interest Expense. Interest expense was $160.2 million for the nine months ended September 30, 2019 compared to $131.5 million for the nine months ended September 30, 2018, an increase of $28.7 million, or 21.8%. Interest expense consisted of the following (in millions):

	Nine Months Ended September 30,	
	2019	**2018**
Senior Notes	$ 114.6	$ 120.0
ENLK Credit Facility	0.3	15.2
Related party debt	48.0	—
Capitalized interest	(4.1)	(5.1)
Amortization of debt issue costs and net discounts (premiums)	3.9	3.2
Secured term loan receivable adjustment	(2.2)	—
Other	(0.3)	(1.8)
Total	$ 160.2	$ 131.5

Income (Loss) from Unconsolidated Affiliate Investments. Income from unconsolidated affiliate investments was $14.0 million for the nine months ended September 30, 2019 compared to $11.7 million for the nine months ended September 30, 2018, an increase of $2.3 million. The increase was primarily attributable to additional income of $1.3 million from our GCF investment as a result of higher fractionation revenues and lower operating expenses and additional income of $1.0 million from our Cedar Cove JV.

Critical Accounting Policies

Information regarding our critical accounting policies is included in Item 7 of our Annual Report on Form 10-K for the year ended December 31, 2018, except for our critical accounting policy on leases, which changed as a result of the adoption of ASC 842 on January 1, 2019. See “Item 1. Financial Statements—Note 5” for information on our leases accounting policy.

Liquidity and Capital Resources

Cash Flows from Operating Activities. Net cash provided by operating activities was $769.8 million for the nine months ended September 30, 2019 compared to $543.8 million for the nine months ended September 30, 2018. Operating cash flows and changes in working capital for comparative periods were as follows (in millions):

	Nine Months Ended September 30,	
	2019	2018
Operating cash flows before working capital	$ 655.5	$ 689.8
Changes in working capital	114.3	(146.0)

Operating cash flows before changes in working capital decreased $34.3 million for the nine months ended September 30, 2019 compared to the nine months ended September 30, 2018. The primary contributors to the decrease in operating cash flows were as follows:

- General and administrative expenses excluding unit-based compensation increased $9.8 million primarily due to higher transaction costs related to the Merger in January 2019. For more information, see "Results of Operations."

- Operating expenses excluding unit-based compensation increased $19.3 million primarily due to expanded operations. For more information, see "Results of Operations."

- Interest expense, excluding amortization of debt issue costs and net discounts, increased $28.0 million.

These decreases to operating cash flows were partially offset by a $23.2 million increase in gross operating margin, excluding unrealized gains and losses on derivative activity and excluding non-cash revenue recognized from the restructuring of a contract. The changes in working capital for the nine months ended September 30, 2019 compared to the nine months ended September 30, 2018 were primarily due to fluctuations in trade receivable and payable balances due to timing of collection and payments, changes in inventory balances attributable to normal operating fluctuations, and fluctuations in accrued revenue and accrued cost of sales.

Cash Flows from Investing Activities. Net cash used in investing activities was $583.0 million for the nine months ended September 30, 2019, compared to $633.0 million for the nine months ended September 30, 2018. Our primary investing cash flows were as follows (in millions):

	Nine Months Ended September 30,	
	2019	2018
Growth capital expenditures	$ (560.0)	$ (608.8)
Maintenance capital expenditures	(34.5)	(30.6)
Proceeds from sale of property	13.7	1.5

Growth capital expenditures decreased $48.8 million for the nine months ended September 30, 2019 compared to the nine months ended September 30, 2018. The decrease was primarily due to lower overall growth capital expenditures due to the completion of Avenger and the Lobo III gas processing plant in the Delaware Basin in 2018, compared to the capital expenditures in 2019 related to the Lobo III cryogenic gas processing plant expansion, the Thunderbird Plant, the expansion of the Cajun-Sibon NGL pipeline, and the expansion of the Riptide processing plant.

Proceeds from the sale of assets increased $12.2 million for the nine months ended September 30, 2019, primarily due to the sale of certain non-core assets during 2019.

Cash Flows from Financing Activities. Net cash used in financing activities was $184.6 million for the nine months ended September 30, 2019 and net cash provided by financing activities was $122.0 million for the nine months ended September 30, 2018. Our primary financing activities consisted of the following (in millions):

	Nine Months Ended September 30,	
	2019	2018
Net borrowings on the ENLK Credit Facility	$ —	$ 765.0
Net borrowings on related party debt	663.5	—
Net repayments on the 2019 unsecured senior notes	(400.0)	—
Proceeds from issuance of common units	—	46.1
Contributions by non-controlling interests (1)	78.6	122.0
Payment of installment payable for EOGP acquisition	—	(250.0)
Distributions to common units	(416.4)	(413.0)
Distributions to general partner interest (including incentive distribution rights) (2)	(15.6)	(46.3)
Distributions to non-controlling interests	(18.0)	(37.6)
Distributions to Series B Preferred Units	(50.3)	(48.5)
Distributions to Series C Preferred Units	(12.0)	(12.0)

____
(1) Represents contributions from NGP to the Delaware Basin JV of $78.6 million and $73.6 million for the nine months ended September 30, 2019 and 2018, respectively, and $48.6 million from ENLC to EOGP for the nine months ended September 30, 2018.
(2) At the closing of the Merger, our general partner’s incentive distribution rights were eliminated.

For the nine months ended September 30, 2018, we sold an aggregate of 2.6 million ENLK common units under an equity distribution agreement, generating proceeds of $46.1 million.

For the nine months ended September 30, 2019, distributions to common units include $139.4 million related to ENLK common units prior to the Merger, and $277.0 million was distributed to ENLC subsequent to the Merger.

Distributions to non-controlling interests included distributions to NGP for its ownership in the Delaware Basin JV and distributions to Marathon Petroleum Corporation for its ownership in the Ascension JV.

Subsequent to the closing of the Merger, ENLK no longer has publicly held common units. See “Item 1. Financial Statements—Note 7” for information on distributions to holders of the Series B Preferred Units and Series C Preferred Units.

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

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

We expect our remaining 2019 growth capital expenditures, including capital contributions to our unconsolidated affiliate investments, to be approximately $120 million to $200 million, net of $31 million to $51 million which we expect to come from our joint venture partners. We expect our remaining 2019 maintenance capital expenditures to be approximately $10 million to $20 million. Our primary capital projects for the remainder of 2019 include the ongoing construction of the Tiger Plant in the Delaware Basin, and continued development of our existing systems. See “Recent Developments” for further details.

We expect to fund growth capital expenditures from the proceeds of borrowings under the Consolidated Credit Facility, operating cash flows, and proceeds from other debt and equity sources, including capital contributions by joint venture partners that relate to the non-controlling interest share of our consolidated entities. We expect to fund our maintenance capital expenditures from operating cash flows. In 2019, 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. No off-balance sheet arrangements existed as of September 30, 2019.

Total Contractual Cash Obligations. A summary of contractual cash obligations as of September 30, 2019 is as follows (in millions):

	Payments Due by Period						
	Total	Remainder 2019	2020	2021	2022	2023	Thereafter
Long-term debt obligations	$ 3,100.0	$ —	$ —	$ —	$ —	$ —	$ 3,100.0
Related party debt	1,513.5	—	—	850.0	—	—	663.5
Interest payable on fixed long-term debt obligations	2,592.2	78.1	176.0	176.0	176.0	176.0	1,810.1
Operating lease obligations	142.7	6.7	23.5	17.1	10.2	9.0	76.2
Purchase obligations	29.6	29.6	—	—	—	—	—
Pipeline capacity and deficiency agreements (1)	198.1	9.7	37.2	37.1	31.1	28.1	54.9
Inactive easement commitment (2)	10.0	—	—	—	10.0	—	—
Total contractual obligations	$ 7,586.1	$ 124.1	$ 236.7	$ 1,080.2	$ 227.3	$ 213.1	$ 5,704.7

(1) Consists of pipeline capacity payments for firm transportation and deficiency agreements.
(2) Amounts related to inactive easements paid as utilized by us with balance due in 2022 if not utilized.

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

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

Our contractual cash obligations for the remainder of 2019 are expected to be funded from cash flows generated from our operations, potential non-core asset sales, and other debt and equity sources.

Indebtedness

Upon the closing of the Merger, the ENLK Credit Facility was canceled, and all indebtedness outstanding thereunder was repaid with cash on hand and proceeds of the Consolidated Credit Facility, which we guarantee. We have a related party debt arrangement with ENLC to fund the operations and growth capital expenditures of ENLK. Interest charged to ENLK for borrowings made through the related party arrangement will be substantially the same as interest charged to ENLC on the borrowings under the Consolidated Credit Facility.

At the closing of the Merger, the Term Loan was assumed by ENLC, and we became a guarantor of the Term Loan.

In addition, as of September 30, 2019, we have $3.1 billion in aggregate principal amount of outstanding unsecured senior notes maturing from 2024 to 2047. As of September 30, 2019, we also have $500.0 million in aggregate principal amount of indebtedness through the related party debt arrangement with ENLC relating to ENLC's 5.375% unsecured senior notes due 2029.

See "Item 1. Financial Statements—Note 6" for more information on our outstanding debt instruments.

Recent Accounting Pronouncements

See "Item 1. Financial Statements—Note 2" for more information on recently issued and adopted accounting pronouncements.

Disclosure Regarding Forward-Looking Statements

This Quarterly Report on Form 10-Q contains forward-looking statements that are based on information currently available to management as well as management's assumptions and beliefs. 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 statements reflect our current views with respect to future events, based on what we believe are reasonable assumptions; however, such statements are subject to certain risks and uncertainties. In addition to the specific uncertainties discussed elsewhere in this Quarterly Report on Form 10-Q, the risk factors set forth in Part II, "Item 1A. Risk Factors" of this report and in Part I, "Item 1A. Risk Factors" of our Annual Report on Form 10-K for the year ended December 31, 2018 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.

In particular, on October 18, 2011, the CFTC adopted final rules under the Dodd-Frank Act establishing position limits for certain energy commodity futures and options contracts and economically equivalent swaps, futures, and options. The position limit levels set the maximum amount of covered contracts that a trader may own or control separately or in combination, net long or short. The final rules also contained limited exemptions from position limits which would be phased in over time for certain bona fide hedging transactions and positions. The CFTC's original position limits rule was challenged in court by two industry associations and was vacated and remanded by a federal district court. The CFTC proposed and revised new rules in November 2013 and December 2016, respectively, that would place limits on positions in certain core futures and equivalent swaps contracts for or linked to certain physical commodities, subject to exceptions for certain bona fide hedging transactions. The CFTC sought comment on the position limits rules as reproposed and revised, but the new rules have not yet been issued in final form, and the impact of any final provisions on us is uncertain at this time.

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

Commodity Price Risk

We are subject to risks due to fluctuations in commodity prices. Approximately 90% of our gross operating margin for the nine months ended September 30, 2019 was generated from arrangements with fee-based structures with minimal direct commodity price exposure. Our exposure to these commodity price fluctuations is primarily in the gas processing component of our business. We currently process gas under four main types of contractual arrangements (or a combination of these types of contractual arrangements) as summarized below.

1. *Fee-based contracts.* Under fee-based contracts, we earn our fees through (1) stated fixed-fee arrangements in which we are paid a fixed fee per unit of volume processed or (2) arrangements where we purchase and resell commodities in connection with providing the related processing service and earn a net margin through a fee-like deduction subtracted from the purchase price of the commodities.

2. *Processing margin contracts.* Under these contracts, we pay the producer for the full amount of inlet gas to the plant, and we make a margin based on the difference between the value of liquids recovered from the processed natural gas as compared to the value of the natural gas volumes lost and the cost of fuel used in processing. The shrink and fuel losses are referred to as plant thermal reduction, or PTR. Our margins from these contracts are high during periods of high liquids prices relative to natural gas prices and can be negative during periods of high natural gas prices relative to liquids prices. However, we mitigate our risk of processing natural gas when margins are negative primarily through our ability to bypass processing when it is not profitable for us or by contracts that revert to a minimum fee for processing if the natural gas must be processed to meet pipeline quality specifications. For the nine months ended September 30, 2019, less than 1% of our gross operating margin was generated from processing margin contracts.

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

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

For the nine months ended September 30, 2019, approximately 7% of our gross operating margin was generated from POL or POP contracts.

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

We have hedged our exposure to fluctuations in prices for natural gas, NGLs, crude oil, and condensate volumes produced for our account. We hedge our exposure based on volumes we consider hedgeable (volumes committed under contracts that are long term in nature) versus total volumes that include volumes that may fluctuate due to contractual terms, such as contracts with month-to-month processing options. Further, we have tailored our hedges to generally match the NGL product composition and the NGL and natural gas delivery points to those of our physical equity volumes. The NGL hedges cover specific NGL products based upon our expected equity NGL composition.

The following table sets forth certain information related to derivative instruments outstanding at September 30, 2019 mitigating the risks associated with the gas processing and fractionation components of our business. The relevant payment index price for liquids is the monthly average of the daily closing price for deliveries of commodities into Mont Belvieu, Texas as reported by Oil Price Information Service. The relevant index price for natural gas is Henry Hub Gas Daily as defined by the pricing dates in the swap contracts.

Period	Underlying	Notional Volume	We Pay	We Receive (1)	Fair Value Asset/(Liability) (In millions)
October 2019 - March 2020	Ethane	271 (MBbls)	$0.1841/gal	Index	$ (0.5)
October 2019 - July 2020	Propane	725 (MBbls)	Index	$0.4616/gal	2.3
October 2019 - July 2020	Normal butane	89 (MBbls)	Index	$0.5299/gal	—
October 2019 - July 2020	Natural gasoline	70 (MBbls)	Index	$1.0541/gal	0.1
October 2019 - July 2020	Natural gas	17,968 (MMBtu/d)	Index	$2.4223/MMBtu	0.3
October 2019 - December 2022	Crude and condensate	13,546 (MBbls)	Index	$53.07/bbl	11.0
					$ 13.2

(1) Weighted average.

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 September 30, 2019, outstanding natural gas swap agreements, NGL swap agreements, swing swap agreements, storage swap agreements, and other derivative instruments were a net fair value asset of $13.2 million. The aggregate effect of a hypothetical 10% change, increase or decrease, in gas, crude and condensate, and NGL prices would result in a change of approximately $4.7 million in the net fair value of these contracts as of September 30, 2019.

Interest Rate Risk

We are exposed to interest rate risk on the Consolidated Credit Facility and the Term Loan through the related party debt arrangement with ENLC. At September 30, 2019, we had $1,513.5 million in outstanding borrowings under the related party debt arrangement, of which $1,013.5 million was related to the Consolidated Credit Facility and the Term Loan. In April 2019, we entered into $850.0 million of interest rate swaps to reduce the variability of cash outflows associated with interest payments related to our long-term debt with variable interest rates. These swaps have been designated as cash flow hedges. See “Item 1. Financial Statements—Note 10” for more information on our outstanding derivatives. A 1.0% increase or decrease in interest rates would change our annualized interest expense by approximately $10.1 million related to the Consolidated Credit Facility and the Term Loan. This change in interest expense would be partially offset by an $8.5 million change related to our open interest rate swap hedge.

We are not exposed to changes in interest rates with respect to our senior unsecured notes due in 2024, 2025, 2026, 2044, 2045, or 2047 or ENLC’s senior unsecured note due in 2029, through the related party debt arrangement with ENLC, as these are fixed-rate obligations. The estimated fair value of the senior unsecured notes was approximately $3,250.8 million as of September 30, 2019, based on market prices of similar debt at September 30, 2019. Market risk is estimated as the potential decrease in fair value of our long-term debt resulting from a hypothetical increase of 1.0% in interest rates. Such an increase in interest rates would result in an approximate $237.2 million decrease in fair value of the senior unsecured notes at September 30, 2019. See “Item 1. Financial Statements—Note 6” for more information on our outstanding indebtedness.

Item 4. Controls and Procedures

a. Evaluation of Disclosure Controls and Procedures

We carried out an evaluation, under the supervision and with the participation of our management, including the Chief Executive Officer and Chief Financial Officer of our general partner, 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 (September 30, 2019), our disclosure controls and procedures were effective to provide reasonable assurance that information required to be disclosed by us in the reports we file or submit under the Securities Exchange Act of 1934 is recorded, processed, summarized, and reported within the time period specified in the applicable rules and forms, and that such information is accumulated and communicated to management, including the Chief Executive Officer and Chief Financial Officer, to allow timely decisions regarding required disclosure.

b. Changes in Internal Control Over Financial Reporting

Effective January 1, 2019, we adopted ASC 842. The adoption of this accounting standard had no material impact on our operating income, results of operations, financial condition, or cash flows. While the adoption of ASC 842 did not materially affect our internal control over financial reporting, we did implement certain changes to our related lease control activities, including changes to our policies related to leases, training, ongoing lease contract review requirements, and gathering of information to comply with disclosure requirements. Furthermore, there has been no change in our internal control over financial reporting that occurred in the three months ended September 30, 2019 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. In the opinion of management, any liabilities that may result from these claims would not individually or in the aggregate have a material adverse effect on our financial position, results of operations, or cash flows.

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, 2018.

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
2.1	—	Agreement and Plan of Merger, dated as of October 21, 2018, by and among EnLink Midstream, LLC, EnLink Midstream Manager, LLC, NOLA Merger Sub, LLC, EnLink Midstream Partners, LP, and EnLink Midstream GP, LLC (incorporated by reference to Exhibit 2.1 to our Current Report on Form 8-K dated October 21, 2018, filed with the Commission on October 22, 2018, file No. 001-36340).
3.1	—	Certificate of Limited Partnership of EnLink Midstream Partners, LP (incorporated by reference to Exhibit 3.1 to our Registration Statement on Form S-1, file No. 333-97779).
3.2	—	Certificate of Amendment to the Certificate of Limited Partnership of EnLink Midstream Partners, LP (incorporated by reference to Exhibit 3.2 to our Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2012, filed with the Commission on August 7, 2012, file No. 000-50067).
3.3	—	Second Amendment to the Certificate of Limited Partnership of EnLink Midstream Partners, LP (incorporated by reference to Exhibit 3.3 to our Current Report on Form 8-K dated March 6, 2014, filed with the Commission on March 11, 2014, file No. 001-36340).
3.4	—	Third Amendment to the Certificate of Limited Partnership of EnLink Midstream Partners, LP (incorporated by reference to Exhibit 3.1 to our Current Report on Form 8-K dated June 16, 2017, filed with the Commission on June 19, 2017, file No. 001-36340).
3.5	—	Tenth Amended and Restated Agreement of Limited Partnership of EnLink Midstream Partners, LP, dated as of January 25, 2019 (incorporated by reference to Exhibit 3.1 to our Current Report on Form 8-K dated January 25, 2019, filed with the Commission on January 29, 2019, file No. 001-36340).
3.6	—	Certificate of Formation of EnLink Midstream GP, LLC (incorporated by reference to Exhibit 3.7 to our Registration Statement on Form S-1, file No. 333-97779).
3.7	—	Certificate of Amendment to the Certificate of Formation of EnLink Midstream GP, LLC (incorporated by reference to Exhibit 3.12 to our Registration Statement on Form S-3, file No. 333-194465).
3.8	—	Fourth Amended and Restated Limited Liability Company Agreement of EnLink Midstream GP, LLC, dated as of July 18, 2018 (incorporated by reference to Exhibit 3.1 to our Current Report on Form 8-K dated July 17, 2018, filed with the Commission on July 23, 2018, file No. 001-36340).
10.1	† —	Form of EnLink Midstream Operating, LP Amended and Restated Severance Agreement (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K dated September 18, 2019, filed with the Commission on September 23, 2019, file No. 001-36340).
10.2	† —	Form of EnLink Midstream Operating, LP Amended and Restated Change in Control Agreement (incorporated by reference to Exhibit 10.2 to our Current Report on Form 8-K dated September 18, 2019, filed with the Commission on September 23, 2019, file No. 001-36340).
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 Partners, LP's Quarterly Report on Form 10-Q for the quarter ended September 30, 2019, formatted in inline XBRL (eXtensible Business Reporting Language): (i) Consolidated Balance Sheets as of September 30, 2019 and December 31, 2018, (ii) Consolidated Statements of Operations for the three and nine months ended September 30, 2019 and 2018, (iii) Consolidated Statements of Changes in Partners' Equity for the three months ended September 30, 2019 and 2018, three months ended June 30, 2019 and 2018, and three months ended March 31, 2019 and 2018, (iv) Consolidated Statements of Cash Flows for the nine months ended September 30, 2019 and 2018, and (v) the Notes to Consolidated Financial Statements.
104 *	—	Cover Page Interactive Data File (formatted as Inline XBRL and contained in Exhibit 101).

* Filed herewith.

† As required by Item 15(a)(3), this Exhibit is identified as a compensatory benefit plan or arrangement.

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 Partners, LP

By: EnLink Midstream GP, LLC,
its general partner

By: /s/ ERIC D. BATCHELDER
Eric D. Batchelder
Executive Vice President and Chief Financial Officer

November 8, 2019

Exhibit 31.1

CERTIFICATIONS

I, Barry E. Davis, certify that:

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

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

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

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

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

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

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

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

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

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

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

Date: November 8, 2019

/s/ BARRY E. DAVIS

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

Exhibit 31.2

CERTIFICATIONS

I, Eric D. Batchelder, certify that:

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

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

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

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

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

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

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

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

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

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

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

Date: November 8, 2019

/s/ ERIC D. BATCHELDER
Eric D. Batchelder
Chief Financial Officer
(principal financial and accounting officer)

Exhibit 32.1

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

In connection with the Quarterly Report of EnLink Midstream Partners, LP (the “Registrant”) on Form 10-Q of EnLink Midstream Partners, LP for the quarter ended September 30, 2019 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 GP, LLC, and Eric D. Batchelder, Chief Financial Officer of EnLink Midstream GP, LLC, certifies, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to his knowledge:

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

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

Date: November 8, 2019	/s/ BARRY E. DAVIS
	Barry E. Davis
	Chief Executive Officer
Date: November 8, 2019	/s/ ERIC D. BATCHELDER
	Eric D. Batchelder
	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.