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, 2018

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)

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 and post 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 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 1, 2018 , the Registrant had 353,100,985 common units outstanding.

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DEFINITIONS

The following terms as defined are used in this document:

Defined Term	Definition
/d	Per day.
2017 EDA	Equity Distribution Agreement entered into by ENLK in August 2017 with UBS Securities LLC, Barclays Capital Inc., BMO Capital Markets Corp., Merrill Lynch, Pierce, Fenner & Smith Incorporated, Citigroup Global Markets Inc., Jefferies LLC, Mizuho Securities USA LLC, RBC Capital Markets, LLC, SunTrust Robinson Humphrey, Inc., and Wells Fargo Securities, LLC to sell up to $600.0 million in aggregate gross sales of our common units from time to time through an “at the market” equity offering program.
AMZ	Alerian MLP Index for Master Limited Partnerships.
ASC	The FASB Accounting Standards Codification.
ASC 606	ASC 606, *Revenue from Contracts with Customers*.
ASU	The FASB Accounting Standards Update.
Ascension JV	Ascension Pipeline Company, LLC, a joint venture between a subsidiary of ENLK and a subsidiary of Marathon Petroleum Corporation in which ENLK owns a 50% interest and Marathon Petroleum Corporation owns a 50% interest. The Ascension JV, which began operations in April 2017, owns an NGL pipeline that connects ENLK’s Riverside fractionator to Marathon Petroleum Corporation’s Garyville refinery.
Bbls	Barrels.
Bcf	Billion cubic feet.
Cedar Cove JV	Cedar Cove Midstream LLC, a joint venture between a subsidiary of ENLK and a subsidiary of Kinder Morgan, Inc. in which ENLK owns a 30% interest and Kinder Morgan, Inc. owns a 70% interest. The Cedar Cove JV, which was formed in November 2016, owns gathering and compression assets in Blaine County, Oklahoma, located in the STACK play.
CFTC	U.S. Commodity Futures Trading Commission.
CNOW	Central Northern Oklahoma Woodford Shale.
Devon	Devon Energy Corporation.
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.
ENLC	EnLink Midstream, LLC.
ENLK	EnLink Midstream Partners, LP or EnLink Midstream Partners, LP together with its consolidated subsidiaries. Also referred to as the “Partnership.”
EOGP	EnLink Oklahoma Gas Processing, LP or EnLink Oklahoma Gas Processing, LP together with, when applicable, its consolidated subsidiaries. EOGP is a partnership in which ENLK and ENLC hold an 83.9% and 16.1% interest, respectively.
FASB	Financial Accounting Standards Board.
FERC	Federal Energy Regulatory Commission.
GAAP	Generally accepted accounting principles in the United States of America.
Gal	Gallons.
GCF	Gulf Coast Fractionators, which owns an NGL fractionator in Mont Belvieu, Texas. ENLK owns 38.75% of GCF.
GIP	Global Infrastructure Management, LLC, an independent infrastructure fund manager, itself, or its affiliates, including GIP III Stetson I, L.P. and GIP III Stetson II, L.P.
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.
Greater Chickadee	Crude oil gathering system in Upton and Midland counties, Texas in the Permian Basin.
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.
HEP	Howard Energy Partners. ENLK sold its 31% ownership interest in HEP in March 2017.
ISDAs	International Swaps and Derivatives Association Agreements.
Mcf	Thousand cubic feet.
MMbtu	Million British thermal units.
MMcf	Million cubic feet.
MVC	Minimum volume commitment.
NGL	Natural gas liquid.
NGP	NGP Natural Resources XI, LP
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.
POL contracts	Percentage-of-liquids contracts.
POP contracts	Percentage-of-proceeds contracts.
Series B Preferred Units	Series B Cumulative Convertible Preferred Units.
Series C Preferred Units	Series C Fixed-to-Floating Rate Cumulative Redeemable Perpetual Preferred Units.
STACK	Sooner Trend Anadarko Basin Canadian and Kingfisher Counties in Oklahoma.
VEX	ENLK’s Victoria Express Pipeline and related truck terminal and storage assets located in the Eagle Ford Shale in South Texas.

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

	September 30, 2018	December 31, 2017
	(Unaudited)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 63.6	$ 30.8
Accounts receivable:		
Trade, net of allowance for bad debt of $0.3 and $0.3, respectively	198.0	50.1
Accrued revenue and other	817.2	576.6
Related party	0.7	102.7
Fair value of derivative assets	12.5	6.8
Natural gas and NGLs inventory, prepaid expenses, and other	153.4	39.7
Total current assets	1,245.4	806.7
Property and equipment, net of accumulated depreciation of $2,859.3 and $2,533.0, respectively	6,875.7	6,587.0
Intangible assets, net of accumulated amortization of $391.3 and $298.7, respectively	1,404.5	1,497.1
Goodwill	422.3	422.3
Investment in unconsolidated affiliates	84.5	89.4
Other assets, net	41.2	11.5
Total assets	$ 10,073.6	$ 9,414.0
LIABILITIES AND PARTNERS' EQUITY		
Current liabilities:		
Accounts payable and drafts payable	$ 130.6	$ 66.9
Accounts payable to related party	5.0	18.4
Accrued gas, NGLs, condensate, and crude oil purchases	656.9	476.1
Fair value of derivative liabilities	21.9	8.4
Installment payable, net of discount of $0.5 at December 31, 2017	—	249.5
Current maturities of long-term debt	399.6	—
Other current liabilities	259.8	222.4
Total current liabilities	1,473.8	1,041.7
Long-term debt	3,835.9	3,467.8
Asset retirement obligations	14.6	14.2
Other long-term liabilities	20.7	33.9
Deferred tax liability	44.4	46.3
Fair value of derivative liabilities	7.0	—
Redeemable non-controlling interest	6.2	4.6
Partners' equity:		
Common unitholders (353,098,287 and 349,702,372 units issued and outstanding, respectively)	2,519.8	2,791.6
Series B preferred unitholders (58,306,274 and 57,056,281 units issued and outstanding, respectively)	884.6	864.1
Series C preferred unitholders (400,000 units outstanding)	401.1	395.1
General partner interest (1,594,974 equivalent units outstanding)	206.2	207.3
Accumulated other comprehensive loss	(2.1)	(2.1)
Non-controlling interest	661.4	549.5
Total partners' equity	4,671.0	4,805.5
Total liabilities and partners' equity	$ 10,073.6	$ 9,414.0

See accompanying notes to consolidated financial statements.

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

	Three Months Ended September 30, 2018	Three Months Ended September 30, 2017	Nine Months Ended September 30, 2018	Nine Months Ended September 30, 2017
	(Unaudited)			
Revenues:				
Product sales	$ 1,832.2	$ 1,056.7	$ 4,766.5	$ 2,973.9
Product sales—related parties	10.2	35.3	41.0	107.3
Midstream services	241.5	136.4	476.1	395.7
Midstream services—related parties	35.8	175.0	377.2	507.6
Loss on derivative activity	(5.4)	(5.5)	(20.1)	(1.1)
Total revenues	2,114.3	1,397.9	5,640.7	3,983.4
Operating costs and expenses:				
Cost of sales (1)	1,696.6	1,053.2	4,403.7	2,987.9
Operating expenses	114.7	102.1	337.3	308.8
General and administrative	39.2	30.0	94.5	94.6
Loss on disposition of assets	—	1.1	1.3	0.8
Depreciation and amortization	146.7	136.3	430.1	407.1
Impairments	24.6	1.8	24.6	8.8
Gain on litigation settlement	—	—	—	(26.0)
Total operating costs and expenses	2,021.8	1,324.5	5,291.5	3,782.0
Operating income	92.5	73.4	349.2	201.4
Other income (expense):				
Interest expense, net of interest income	(44.1)	(48.9)	(131.5)	(140.5)
Gain on extinguishment of debt	—	—	—	9.0
Income from unconsolidated affiliates	4.3	4.4	11.7	5.0
Other income	0.1	0.3	0.3	0.5
Total other expense	(39.7)	(44.2)	(119.5)	(126.0)
Income before non-controlling interest and income taxes	52.8	29.2	229.7	75.4
Income tax benefit (provision)	(0.9)	(0.5)	0.2	(0.7)
Net income	51.9	28.7	229.9	74.7
Net income attributable to non-controlling interest	8.7	3.2	27.7	1.5
Net income attributable to ENLK	$ 43.2	$ 25.5	$ 202.2	$ 73.2
General partner interest in net income	$ 7.7	$ 10.6	$ 29.5	$ 27.3
Limited partners' interest in net income (loss) attributable to ENLK	$ 5.2	$ (8.6)	$ 85.7	$ (18.4)
Series B preferred interest in net income attributable to ENLK	$ 24.3	$ 22.8	$ 69.0	$ 63.6
Series C preferred interest in net income attributable to ENLK	$ 6.0	$ 0.7	$ 18.0	$ 0.7
Net income (loss) attributable to ENLK per limited partners' unit:				
Basic common unit	$ 0.01	$ (0.02)	$ 0.24	$ (0.05)
Diluted common unit	$ 0.01	$ (0.02)	$ 0.24	$ (0.05)

(1) Includes related party cost of sales of $23.0 million and $47.3 million for the three months ended September 30, 2018 and 2017 , respectively , and $103.8 million and $126.9 million for the nine months ended September 30, 2018 and 2017 , respectively .

See accompanying notes to consolidated financial statements.

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2018	2017	2018	2017
	(Unaudited)			
Net income	$ 51.9	$ 28.7	$ 229.9	$ 74.7
Loss on designated cash flow hedge	—	—	—	(2.2)
Comprehensive income	51.9	28.7	229.9	72.5
Comprehensive income attributable to non-controlling interest	8.7	3.2	27.7	1.5
Comprehensive income attributable to EnLink Midstream Partners, LP	$ 43.2	$ 25.5	$ 202.2	$ 71.0

See accompanying notes to consolidated financial statements.

ENLINK MIDSTREAM PARTNERS, LP
Consolidated Statement of Changes in Partners' Equity
Nine Months Ended September 30, 2018
(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	$2,791.6	349.7	$864.1	57.1	$395.1	0.4	$207.3	1.6	$ (2.1)	$ 549.5	$4,805.5	$ 4.6
Issuance of common units	46.1	2.6	—	—	—	—	—	—	—	—	46.1	—
Conversion of restricted units for common units, net of units withheld for taxes	(5.6)	0.8	—	—	—	—	—	—	—	—	(5.6)	—
Unit-based compensation	16.4	—	—	—	—	—	15.7	—	—	—	32.1	—
Distributions	(413.0)	—	(48.5)	1.2	(12.0)	—	(46.3)	—	—	(37.6)	(557.4)	—
Contributions from non-controlling interests	—	—	—	—	—	—	—	—	—	122.0	122.0	—
Fair value adjustment related to redeemable non-controlling interest	(1.4)	—	—	—	—	—	—	—	—	—	(1.4)	1.4
Net income	85.7	—	69.0	—	18.0	—	29.5	—	—	27.5	229.7	0.2
Balance, September 30, 2018	$2,519.8	353.1	$884.6	58.3	$401.1	0.4	$206.2	1.6	$ (2.1)	$ 661.4	$4,671.0	$ 6.2

See accompanying notes to consolidated financial statements.

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

	Nine Months Ended September 30,	
	2018	2017
	(Unaudited)	
Cash flows from operating activities:		
Net income	$ 229.9	$ 74.7
Adjustments to reconcile net income to net cash provided by operating activities:		
Impairments	24.6	8.8
Depreciation and amortization	430.1	407.1
Non-cash unit-based compensation	31.6	38.7
Loss on derivatives recognized in net income	20.1	1.1
Gain on extinguishment of debt	—	(9.0)
Cash settlements on derivatives	(4.3)	(5.9)
Amortization of debt issue costs, net discount (premium) of notes and installment payable	3.2	21.6
Distribution of earnings from unconsolidated affiliates	14.0	4.1
Income from unconsolidated affiliates	(11.7)	(5.0)
Non-cash revenue from contract restructuring	(45.5)	—
Other operating activities	(2.2)	1.1
Changes in assets and liabilities, net of assets acquired and liabilities assumed:		
Accounts receivable, accrued revenue, and other	(292.2)	(56.9)
Natural gas and NGLs inventory, prepaid expenses, and other	(92.9)	(48.6)
Accounts payable, accrued gas and crude oil purchases, and other accrued liabilities	239.1	101.2
Net cash provided by operating activities	543.8	533.0
Cash flows from investing activities:		
Additions to property and equipment	(639.4)	(662.5)
Proceeds from sale of unconsolidated affiliate investment	—	189.7
Investment in unconsolidated affiliates	(0.1)	(11.8)
Distribution from unconsolidated affiliates in excess of earnings	2.7	7.3
Other investing activities	3.8	2.0
Net cash used in investing activities	(633.0)	(475.3)
Cash flows from financing activities:		
Proceeds from borrowings	1,979.0	2,151.9
Payments on borrowings	(1,214.0)	(1,940.3)
Payment of installment payable for EOGP acquisition	(250.0)	(250.0)
Debt financing costs	—	(5.5)
Conversion of restricted units, net of units withheld for taxes	(5.6)	(5.2)
Proceeds from issuance of common units	46.1	92.3
Proceeds from issuance of Series C Preferred Units	—	393.7
Distributions to non-controlling interests	(37.6)	(17.0)
Contributions by non-controlling interests, including contributions from affiliates of $48.6 and $59.3, respectively	122.0	105.5
Distributions to Series B Preferred Units	(48.5)	—
Distributions to Series C Preferred Units	(12.0)	—
Distributions to common unitholders and to general partner	(459.3)	(452.3)
Other financing activities	1.9	(0.7)
Net cash provided by financing activi ties	122.0	72.4
Net increase in cash and cash equivalents	32.8	130.1
Cash and cash equivalents, beginning of period	30.8	11.6
Cash and cash equivalents, end of period	$ 63.6	$ 141.7
Supplemental disclosures of cash flow information:		
Cash paid for interest	$ 106.3	$ 93.2
Cash paid for income taxes	$ 0.6	$ 3.6

Non-cash investing activities:				
Non-cash accrual of property and equipment	$	13.3	$	(26.2)
Discounted secured term loan receivable from contract restructuring	$	47.7	$	—

See accompanying notes to consolidated financial statements.

ENLINK MIDSTREAM PARTNERS, LP
Notes to Consolidated Financial Statements
September 30, 2018
(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

EnLink Midstream Partners, LP is a publicly traded Delaware limited partnership formed in 2002. Our common units are traded on the New York Stock Exchange under the symbol "ENLK." Our business activities are conducted through our subsidiary, 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 an indirect, wholly-owned subsidiary of ENLC. ENLC's units are traded on the New York Stock Exchange under the symbol "ENLC."

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. As a result of the transaction:

- GIP, through GIP Stetson I, L.P., acquired all of the equity interests held by subsidiaries of Devon in ENLK and the managing member of ENLC, which amount to 100% of the outstanding limited liability company interests in the managing member of ENLC and approximately 23.1% of the outstanding limited partner interests in ENLK at the closing date. Through this transaction, GIP acquired control of (i) the managing member of ENLC, (ii) ENLC, and (iii) ENLK, as a result of ENLC's indirect ownership of ENLK's general partner; and

- GIP, through GIP Stetson II, L.P., acquired all of the equity interests held by subsidiaries of Devon in ENLC, which amount to approximately 63.8% of the outstanding limited liability company interests in ENLC at the closing date.

On October 21, 2018, ENLK, ENLC, the general partner of ENLK, the managing member of ENLC , and NOLA Merger Sub, LLC, a wholly-owned subsidiary of ENLC ("NOLA Merger Sub"), entered into a definitive agreement and plan of merger (the "Merger Agreement") pursuant to which, subject to the satisfaction or waiver of certain conditions in the Merger Agreement, NOLA Merger Sub will merge with and into ENLK (the "Merger"), with ENLK continuing as the surviving entity and a subsidiary of ENLC. The Merger and the other transactions contemplated by the Merger Agreement and the preferred restructuring agreement entered into concurrently with the Merger Agreement (the "Merger Transactions") are expected to close in the first quarter of 2019, subject to obtaining our unitholder approval, customary regulatory approvals, and other customary closing conditions. See Note 13—Subsequent Event for more information regarding this transaction.

(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. All significant intercompany balances and transactions have been eliminated in consolidation.

(b) Revenue Recognition

We generate the majority of our revenues from midstream energy services, including gathering, transmission, processing, fractionation, storage, condensate stabilization, brine services, and marketing, through various contractual arrangements, which include fee-based contract arrangements or arrangements where we purchase and resell commodities in connection with providing the related service and earn a net margin for our fee. While our transactions vary in form, the essential element of most of our transactions is the use of our assets to transport a product or provide a processed product to an end-user or marketer at the tailgate of the plant, pipeline, or barge, truck, or rail terminal. Revenues from both “Product sales” and “Midstream services” represent revenues from contracts with customers and are reflected on the consolidated statements of operations as follows:

- *Product sales* —Product sales represent the sale of natural gas, NGLs, crude oil, and condensate where the product is purchased and resold in connection with providing our midstream services as outlined above.

- *Midstream services* —Midstream services represent all other revenue generated as a result of performing our midstream services as outlined above.

Adoption of ASC 606

Effective January 1, 2018, we adopted ASC 606 using the modified retrospective method. ASC 606 replaces previous revenue recognition requirements in GAAP and requires entities to recognize revenue at an amount that reflects the consideration to which they expect to be entitled in exchange for transferring goods or services to a customer. ASC 606 also requires significantly expanded disclosures containing qualitative and quantitative information regarding the nature, amount, timing, and uncertainty of revenue and cash flows arising from contracts with customers.

Evaluation of Our Contractual Performance Obligations

In adopting ASC 606, we evaluated our contracts with customers that are within the scope of ASC 606. In accordance with the new revenue recognition framework introduced by ASC 606, we identified our performance obligations under our contracts with customers. These performance obligations include:

- promises to perform midstream services for our customers over a specified contractual term and/or for a specified volume of commodities; and
- promises to sell a specified volume of commodities to our customers.

The identification of performance obligations under our contracts requires a contract-by-contract evaluation of when control, including the economic benefit, of commodities transfers to and from us (if at all). This evaluation of control changed the way we account for certain transactions effective January 1, 2018, specifically those contracts in which there is both a commodity purchase and a midstream service. For contracts where control of commodities transfers to us before we perform our services, we generally have no performance obligation for our services, and accordingly, we do not consider these revenue-generating contracts for purposes of ASC 606. Based on the control determination, all contractually-stated fees that are deducted from our payments to producers or other suppliers for commodities purchased are reflected as a reduction in the cost of such commodity purchases. Alternatively, for contracts where control of commodities transfers to us after we perform our services, we consider these contracts to contain performance obligations for our services. Accordingly, we consider the satisfaction of these performance obligations as revenue-generating and recognize the fees received for satisfying them as midstream services revenues over time as we satisfy our performance obligations. For contracts where control of commodities never transfers to us and we simply earn a fee for our services, we recognize these fees as midstream services revenues over time as we satisfy our performance obligations.

We also evaluate our contractual arrangements that contain a purchase and sale of commodities under the principal/agent provisions in ASC 606. For contracts where we possess control of the commodity and act as principal in the purchase and sale, we record product sales revenue at the price at which the commodities are sold, with a corresponding cost of sales equal to the cost of the commodities when purchased. For contracts in which we do not possess control of the commodity and are acting as an agent, our consolidated statements of operations only reflect midstream services revenues that we earn based on the fees contained in the applicable contract.

Based on our review of our performance obligations in our contracts with customers, we changed the consolidated statement of operations classification for certain transactions from revenue to cost of sales or from cost of sales to revenue. For the three and nine months ended September 30, 2018 , the reclassification of revenues and cost of sales resulted in a net decrease in revenue of approximately $179 million and $480 million , respectively, or 8% and 8% , respectively, compared to total revenues based on accounting prior to the adoption of ASC 606, with an equivalent net decrease in cost of sales. The change in total revenues as a result of the adoption of ASC 606 is made up of the following revenue line item changes (in millions):

	Increase (Decrease) in Revenue Due to ASC 606 Adoption	
	Three Months Ended September 30, 2018	**Nine Months Ended September 30, 2018**
Product sales	$ (71)	$ (149)
Product sales—related parties	(7)	(53)
Midstream services	(98)	(251)
Midstream services—related parties	(3)	(27)
Total	$ (179)	$ (480)

This change in accounting treatment had no impact on our operating income, net income, results of operations, financial condition, or cash flows.

Changes in Accounting Methodology for Certain Contracts

For NGL contracts in which we purchase raw mix NGLs and subsequently transport, fractionate, and market the NGLs, we accounted for these contracts prior to the adoption of ASC 606 as revenue-generating contracts in which the fees we earned for our services were recorded as midstream services revenue on the consolidated statements of operations. As a result of the adoption of ASC 606, we determined that the control, including the economic benefit, of commodities has passed to us once the raw mix NGLs have been purchased from the customer. Therefore, we now consider the contractually-stated fees to serve as pricing mechanisms that reduce the cost of such commodity purchased upon receipt of the raw mix NGLs, rather than being recorded as midstream services revenue. Upon sale of the NGLs to a third-party customer, we record product sales revenue at the price at which the commodities are sold, with a corresponding cost of sales equal to the cost of the commodities purchased.

For our crude oil and condensate service contracts in which we purchase the commodity, we utilize a similar approach under ASC 606 as outlined above for NGL contracts. This treatment is consistent with our accounting for crude oil and condensate service contracts prior to the adoption of ASC 606.

For our natural gas gathering and processing contracts in which we perform midstream services and also purchase the natural gas, we accounted for these contracts prior to the adoption of ASC 606 as revenue-generating contracts in which all contractually-stated fees earned for our gathering and processing services were recorded as midstream services revenue on the statements of operations. As a result of the adoption of ASC 606, we must determine if economic control of the commodities has passed from the producer to us before or after we perform our services (if at all). Control is assessed on a contract-by-contract basis by analyzing each contract's provisions, which can include provisions for: the customer to take its residue gas and/or NGLs in-kind; fixed or actual NGL or keep-whole recovery; commodity purchase prices at weighted average sales price or market index-based pricing; and various other contract-specific considerations. Based on this control assessment, our gathering and processing contracts fall into two primary categories:

- For gathering and processing contracts in which there is a commodity purchase and analysis of the contract provisions indicates that control, including the economic benefit, of the natural gas passes to us when the natural gas is brought into our system, we do not consider these contracts to contain performance obligations for our services. As control of the natural gas passes to us prior to performing our gathering and processing services, we are, in effect, performing our services for our own benefit. Based on this control determination, we consider the contractually-stated fees to serve as pricing mechanisms that reduce the cost of such commodity purchased upon receipt of the natural gas, rather than being recorded as midstream services revenue. Upon sale of the residue gas and/or NGLs to a third-party customer, we record product sales revenue at the price at which the commodities are sold, with a corresponding cost of sales equal to the cost of the commodities purchased.

- For gathering and processing contracts in which there is a commodity purchase and analysis of the contract provisions indicates that control, including the economic benefit, of the natural gas does not pass to us until after the natural gas has been gathered and processed, we consider these contracts to contain performance obligations for our services. Accordingly, we consider the satisfaction of these performance obligations as revenue-generating, and we recognize the fees received for satisfying these performance obligations as midstream services revenues over time as we satisfy our performance obligations.

For midstream service contracts related to NGL, crude oil, or natural gas gathering and processing in which there is no commodity purchase or control of the commodity never passes to us and we simply earn a fee for our services, we consider these contracts to contain performance obligations for our services. Accordingly, we consider the satisfaction of these performance obligations as revenue-generating, and we recognize the fees received for satisfying these performance obligations as midstream services revenue over time as we satisfy our performance obligations. This treatment is consistent with our accounting for these contracts prior to the adoption of ASC 606.

For our natural gas transmission contracts, we determined that control of the natural gas never transfers to us and we simply earn a fee for our services. Therefore, we recognize these fees as midstream services revenue over time as we satisfy our performance obligations. This treatment is consistent with our accounting for natural gas transmission contracts prior to the adoption of ASC 606.

We also evaluate our commodity marketing contracts, under which we purchase and sell commodities in connection with our gas, NGL, and crude and condensate midstream services, pursuant to ASC 606, including the principal/agent provisions. For contracts in which we possess control of the commodity and act as principal in the purchase and sale of commodities, we record product sales revenue at the price at which the commodities are sold, with a corresponding cost of sales equal to the cost of the commodities when purchased. For contracts in which we do not possess control of the commodity and are acting as agent, our consolidated statements of operations only reflect midstream services revenues that we earn based on the fees contained in the applicable contract. This treatment is consistent with our accounting for our commodity marketing contracts prior to the adoption of ASC 606.

Satisfaction of Performance Obligations and Recognition of Revenue

While ASC 606 alters the line item on which certain amounts are recorded on the consolidated statements of operations, ASC 606 did not significantly affect the timing of income and expense recognition on the consolidated statements of operations. Specifically, for our commodity sales contracts, we satisfy our performance obligations at the point in time at which the commodity transfers from us to the customer. This transfer pattern aligns with our billing methodology. Therefore, we recognize product sales revenue at the time the commodity is delivered and in the amount to which we have the right to invoice the customer, which is consistent with our accounting prior to the adoption of ASC 606. For our midstream service contracts that contain revenue-generating performance obligations, we satisfy our performance obligations over time as we perform the midstream service and as the customer receives the benefit of these services over the term of the contract. As permitted by ASC 606, we are utilizing the practical expedient that allows an entity to recognize revenue in the amount to which the entity has a right to invoice, since we have a right to consideration from our customer in an amount that corresponds directly with the value to the customer of our performance completed to date. Accordingly, we continue to recognize revenue over time as our midstream services are performed. Therefore, ASC 606 does not significantly affect the timing of revenue and expense recognition on our consolidated statements of operations, and no cumulative effect adjustment was made to the balance of equity upon our adoption of ASC 606.

We generally accrue one month of sales and the related natural gas, NGL, condensate, and crude oil purchases and reverse these accruals when the sales and purchases are invoiced and recorded in the subsequent month. Actual results could differ from the accrual estimates. We typically receive payment for invoiced amounts within one month, depending on the terms of the contract. We account for taxes collected from customers attributable to revenue transactions and remitted to government authorities on a net basis (excluded from revenues).

Minimum Volume Commitments and Firm Transportation Contracts

Certain gathering and processing agreements in our Texas, Oklahoma, and Crude and Condensate segments provide for quarterly or annual MVCs, including MVCs from Devon from certain of our Barnett Shale assets in North Texas and our Cana gathering and processing assets in Oklahoma. Under these agreements, our customers or suppliers (as “customers” and “suppliers” are determined per application of ASC 606) 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 expected impact to our consolidated statements of operations, resulting from either revenue or reductions to cost of sales, from MVC and firm transportation contractual provisions. All amounts in the table below reflect 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. In addition, amounts in the table below 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.

2018 (remaining)	$	190.9
2019		237.1
2020		225.7
2021		82.3
2022		71.9
Thereafter		231.2
Total	$	1,039.1

In May 2018, we restructured one of our natural gas gathering and processing contracts that included MVCs that were in effect through 2023. Prior to the contract restructuring, we expected $135.1 million in guaranteed future gross operating margin under the contract, generated from either revenue or reductions to cost of sales resulting from both gathering and processing fees as well as shortfall revenue under the MVCs. As a result of the contract restructuring, all MVC provisions were removed from the contract, and we and the counterparty entered into additional agreements pursuant to which: (i) the counterparty made a $19.7 million payment to us on the date of the contract restructuring to satisfy MVC revenue earned up to the date of the contract restructuring; (ii) the counterparty entered into a second lien secured term loan under which the counterparty will pay us $58.0 million in principal payments in various installments ending in May 2023, with interest accruing on the loan balance at 8.0% per annum beginning in 2020; and (iii) the counterparty granted to us a 1.0% term overriding royalty interest through June 2034 in each well located on leasehold interests of the counterparty and connected to the gas gathering system that we operate. As a result of the contract restructuring and in accordance with ASC 606, we recognized $45.5 million of midstream services revenue, which primarily represents the discounted present value of the second lien secured term loan receivable, in the Oklahoma segment in the second quarter of 2018. Pursuant to the contract restructuring, the terms of the restructured contract, other than the MVCs, are the same as the original contract, and we expect to continue recognizing gathering and processing fees on volumes delivered by the customer.

Contributions in Aid of Construction

The adoption of ASC 606 also alters how we account for contributions in aid of construction (“CIAC”). CIAC payments are lump sum payments from third parties to reimburse us for capital expenditures related to the construction of our operating assets and, in most cases, the connection of these operating assets to the third party’s assets. CIAC payments can be paid to us prior to the commencement of construction activities, during construction, or after construction has been completed. Prior to adoption of ASC 606 and in accordance with ASC 980, *Regulated Operations* (“ASC 980”), and the FERC Uniform System of Accounts, we reduced the balance of the related property and equipment by the amount of CIAC payments received. In doing so, CIAC payments previously affected the consolidated statements of operations through reduced depreciation expense over the useful lives of the related property and equipment. Upon adoption of ASC 606, we initially recognize CIAC payments received from customers as deferred revenue, which will be subsequently amortized into revenue over the term of the underlying operational contract. For CIAC payments from noncustomers and for payments related to the construction of regulated operating assets, we continue to reduce the balance of the related property and equipment in accordance with ASC 980 and the FERC Uniform System of Accounts. This change in our CIAC accounting policy was not material to our financial statements for the three and nine months ended September 30, 2018 .

Disaggregation of Revenue and Presentation of Prior Periods

Based on the disclosure requirements of ASC 606, we are presenting revenues disaggregated based on the type of good or service in order to more fully depict the nature of our revenues. See Note 11—Segment Information for the revenue disaggregation information included in the segment information table for the three and nine months ended September 30, 2018 . As we adopted ASC 606 using the modified retrospective method, only the consolidated statement of operations and revenue disaggregation information for the three and nine months ended September 30, 2018 are presented to conform to ASC 606 accounting and disclosure requirements. Prior periods presented in the consolidated financial statements and accompanying notes were not restated in accordance with ASC 606.

(c) Accounting Standards to be Adopted in Future Periods

In February 2016, the FASB issued ASU 2016-02, *Leases (Topic 842) — Amendments to the FASB Accounting Standards Codification* ("ASU 2016-02"), which establishes ASC Topic 842, *Leases* ("ASC 842"). Under ASC 842, lessees will need to recognize virtually all of their leases on the balance sheet by recording a right-of-use asset and lease liability. Lessor accounting is similar to the current model but updated to align with certain changes to the lessee model and the new revenue recognition standard. Existing sale-leaseback guidance is replaced with a new model applicable to both lessees and lessors. Additional revisions have been made to embedded leases, reassessment requirements, and lease term assessments including variable lease payment, discount rate, and lease incentives. ASC 842 is effective for annual reporting periods beginning after December 15, 2018, including interim periods within those annual periods. We will adopt ASC 842 effective January 1, 2019. We are currently assessing the impact of adopting ASC 842 and are in the process of implementing a lease accounting software tool. This assessment includes the evaluation of our current lease contracts and the analysis of contracts that may contain lease components. We are electing to apply certain practical expedients that are 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. While we are still evaluating the complete population of lease contracts, we believe the adoption of ASC 842 will increase our asset and liability balances on the consolidated balance sheets by less than $100 million due to the required recognition of right-of-use assets and corresponding lease liabilities for all lease obligations that are currently classified as operating leases.

In January 2018, the FASB issued ASU 2018-01, *Leases (Topic 842)—Land Easement Practical Expedient for Transition to Topic 842* ("ASU 2018-01"). ASU 2018-01 amends ASC 842 and provides an optional practical expedient to not evaluate under ASC 842 existing or expired land easements that were not previously accounted for as leases under the current leases guidance in ASC 840, *Leases* . Under ASU 2018-01, an entity that elects this practical expedient should evaluate new or modified land easements under ASC 842 beginning at the date that the entity adopts ASC 842. We plan to utilize the practical expedient provided in ASU 2018-01 in conjunction with our adoption of ASC 842.

In July 2018, the FASB issued ASU 2018-11, *Leases (Topic 842)—Targeted Improvements* ("ASU 2018-11"). ASU 2018-11 amends ASC 842 and allows entities to adopt the new leases standard using a modified retrospective approach. Under this new transition method, entities initially apply the new leases standard at the adoption date and recognize a cumulative-effect adjustment to the opening balance of retained earnings in the period of adoption. Additionally, an entity's reporting for the comparative periods presented in the financial statements in which it adopts the new leases standard will continue to be in accordance with current GAAP. We plan to utilize the optional transition method provided in ASU 2018-11 in conjunction with our adoption of ASC 842 in January 2019.

(d) Property & Equipment

Impairment Review. In accordance with ASC 360, *Property, Plant and Equipment* , we evaluate long-lived assets of identifiable business activities for potential impairment whenever events or changes in circumstances indicate that the carrying amount of the assets may not be recoverable. The carrying amount of a long-lived asset is not recoverable when it exceeds the undiscounted sum of the future cash flows expected to result from the use and eventual disposition of the asset. Estimates of expected future cash flows represent management's best estimate based on reasonable and supportable assumptions. When the carrying amount of a long-lived asset is not recoverable, an impairment loss is recognized equal to the excess of the asset's carrying value over its fair value. For the three and 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. For the three and nine months ended September 30, 2017 , we recognized impairments of property and equipment of $1.8 million and $8.8 million , respectively, which related to the carrying values of rights-of-way that we are no longer using and an abandoned brine disposal well.

(3) Intangible Assets

Intangible assets associated with customer relationships are amortized on a straight-line basis over the expected period of benefits of the customer relationships, which 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, 2018			
Customer relationships, beginning of period	$ 1,795.8	$ (298.7)	$ 1,497.1
Amortization expense	—	(92.6)	(92.6)
Customer relationships, end of period	$ 1,795.8	$ (391.3)	$ 1,404.5

The weighted average amortization period is 15.0 years . Amortization expense was $30.9 million and $31.2 million for the three months ended September 30, 2018 and 2017 , respectively, and $92.6 million and $96.2 million for the nine months ended September 30, 2018 and 2017 , respectively.

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

2018 (remaining)	$ 30.9
2019	123.7
2020	123.7
2021	123.7
2022	123.7
Thereafter	878.8
Total	$ 1,404.5

(4) Related Party Transactions

On July 18, 2018, subsidiaries of Devon sold all of their equity interests in ENLK, ENLC, and the managing member of ENLC to GIP. Accordingly, Devon is no longer an affiliate of ENLK or ENLC. The sale did not affect our commercial arrangements with Devon, except that Devon agreed to extend through 2029 certain existing fixed-fee gathering and processing contracts related to the Bridgeport plant in North Texas and the Cana plant in Oklahoma. See Note 1—General for additional information regarding the GIP Transaction. Prior to July 18, 2018, revenues from transactions with Devon are included in “Product sales—related parties” or “Midstream services—related parties” in the consolidated statement of operations. Revenues from transactions with Devon after July 18, 2018 are included in “Product sales” or “Midstream services” in the consolidated statement of operations.

From July 1, 2018 to July 18, 2018 and January 1, 2018 to July 18, 2018, Devon accounted for 2.0% and 7.3% of our revenues, respectively, and for the three and nine months ended September 30, 2017 , Devon accounted for 15.0% and 15.4% of our revenues, respectively. We had an accounts receivable balance related to transactions with Devon of $102.7 million at December 31, 2017 . Additionally, we had an accounts payable balance related to transactions with Devon of $16.3 million at December 31, 2017 .

For the three and nine months ended September 30, 2018 , we recorded cost of sales of $11.3 million and $33.8 million , respectively, and for the three and nine months ended September 30, 2017 , we recorded cost of sales of $9.5 million and $15.0 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 an accounts receivable balance related to transactions with the Cedar Cove JV of $0.7 million at September 30, 2018 . Additionally, we had an accounts payable balance related to transactions with the Cedar Cove JV of $5.0 million at September 30, 2018 . The accounts receivable and payable balances related to transactions with the Cedar Cove JV were immaterial at December 31, 2017 .

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

(5) Long-Term Debt

As of September 30, 2018 and December 31, 2017 , long-term debt consisted of the following (in millions):

	September 30, 2018			December 31, 2017		
	Outstanding Principal	Premium (Discount)	Long-Term Debt	Outstanding Principal	Premium (Discount)	Long-Term Debt
Credit facility due 2020 (1)	$ 765.0	$ —	$ 765.0	$ —	$ —	$ —
2.70% Senior unsecured notes due 2019 (2)	400.0	(0.1)	399.9	400.0	(0.1)	399.9
4.40% Senior unsecured notes due 2024	550.0	1.9	551.9	550.0	2.2	552.2
4.15% Senior unsecured notes due 2025	750.0	(0.9)	749.1	750.0	(1.0)	749.0
4.85% Senior unsecured notes due 2026	500.0	(0.5)	499.5	500.0	(0.6)	499.4
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	(6.2)	443.8	450.0	(6.5)	443.5
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	$ 4,265.0	$ (6.1)	4,258.9	$ 3,500.0	$ (6.3)	3,493.7
Debt issuance cost (3)			(23.4)			(25.9)
Less: Current maturities of long-term debt (2)			(399.6)			—
Long-term debt, net of unamortized issuance cost			$ 3,835.9			$ 3,467.8

(1) Bears interest based on Prime and/or LIBOR plus an applicable margin. The effective interest rate was 4.1% at September 30, 2018 .
(2) The 2.70% senior unsecured notes mature 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 September 30, 2018 .
(3) Net of amortization of $14.5 million and $12.0 million at September 30, 2018 and December 31, 2017 , respectively.

Credit Facility

We have a $1.5 billion unsecured revolving credit facility that matures on March 6, 2020 and includes a $500.0 million letter of credit subfacility. Under our credit facility, we are permitted to (1) subject to certain conditions and the receipt of additional commitments by one or more lenders, increase the aggregate commitments under our credit facility by an additional amount not to exceed $500.0 million and (2) subject to certain conditions and the consent of the requisite lenders, on two separate occasions, extend the maturity date of our credit facility by one year on each occasion. Our credit facility contains certain financial, operational, and legal covenants. Among other things, these covenants include maintaining a ratio of consolidated indebtedness to consolidated EBITDA (which is defined in our credit facility and includes projected EBITDA from certain capital expansion projects) of no more than 5.0 to 1.0. If we consummate one or more acquisitions in which the aggregate purchase price is $50.0 million or more, we can elect to increase the maximum allowed ratio of consolidated indebtedness to consolidated EBITDA to 5.5 to 1.0 for the quarter of the acquisition and the three following quarters.

Borrowings under our credit facility bear interest at our option at the Eurodollar Rate (the LIBOR Rate) plus an applicable margin (ranging from 1.00% to 1.75%) 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 0.0% to 0.75%). The applicable margins vary depending on our credit rating. If we breach certain covenants governing our credit facility, amounts outstanding under our credit facility, if any, may become due and payable immediately.

On June 20, 2018, we amended the change of control provisions of our credit facility to, among other things, designate GIP as Qualifying Owners (as defined in the credit facility). At September 30, 2018 , we were in compliance and expect to be in compliance with the covenants in our credit facility for at least the next twelve months.

As of September 30, 2018 , there were $9.3 million in outstanding letters of credit and $765.0 million outstanding borrowings under our credit facility, leaving approximately $725.7 million available for future borrowing.

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

All other material terms and conditions of our credit facility and outstanding senior unsecured notes are described in Part II, "Item 8. Financial Statements and Supplementary Data—Note 6" in our Annual Report on Form 10-K for the year ended December 31, 2017 .

(6) Partners' Capital

(a) Issuance of Common Units

In August 2017, we entered into the 2017 EDA with UBS Securities LLC, Barclays Capital Inc., BMO Capital Markets Corp., Merrill Lynch, Pierce, Fenner & Smith Incorporated, Citigroup Global Markets Inc., Jefferies LLC, Mizuho Securities USA LLC, RBC Capital Markets, LLC, SunTrust Robinson Humphrey, Inc. and Wells Fargo Securities, LLC (collectively, the "Sales Agents") to sell up to $600.0 million in aggregate gross sales of our common units from time to time through an "at the market" equity offering program. We may also sell common units to any Sales Agent as principal for the Sales Agent's own account at a price agreed upon at the time of sale. We have no obligation to sell any of the common units under the 2017 EDA and may at any time suspend solicitation and offers under the 2017 EDA.

For the nine months ended September 30, 2018 , we sold an aggregate of approximately 2.6 million common units under the 2017 EDA, generating proceeds of approximately $46.1 million (net of approximately $0.5 million of commissions paid to the Sales Agents). We used the net proceeds for general partnership purposes. As of September 30, 2018 , approximately $518.8 million in aggregate gross proceeds remains available to be issued under the 2017 EDA.

(b) Series B Preferred Units

Beginning with the quarter ended September 30, 2017, Series B Preferred Unit distributions are 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 common units over the Cash Distribution Component, divided by (ii) the issue price of $15.00 . Income is allocated to the Series B Preferred Units in an amount equal to the quarterly distribution with respect to the period earned. For the three and nine months ended September 30, 2018 , $24.3 million and $69.0 million of income, respectively, was allocated to the Series B Preferred Units. For the three and nine months ended September 30, 2017 , $22.8 million and $63.6 million of income, respectively, was allocated to the Series B Preferred Units.

A summary of the distribution activity relating to the Series B Preferred Units during the nine months ended September 30, 2018 and 2017 is provided below:

Declaration period	Distribution paid as additional Series B Preferred Units	Cash Distribution (in millions)		Date paid/payable
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
2017				
Fourth Quarter of 2016	1,130,131	$	—	February 13, 2017
First Quarter of 2017	1,154,147	$	—	May 12, 2017
Second Quarter of 2017	1,178,672	$	—	August 11, 2017
Third Quarter of 2017	410,681	$	15.9	November 13, 2017

(c) 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 15 th day of June and December of each year through and including December 15, 2022 and, thereafter, quarterly in arrears on the 15 th 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 distribution rate for the Series C Preferred Units is 6.0% per annum, and we distributed $12.0 million to holders of Series C Preferred Units during the nine months ended September 30, 2018 . Income is allocated to the Series C Preferred Units in an amount equal to the earned distributions for the respective reporting period. For the three and nine months ended September 30, 2018 , $6.0 million and $18.0 million of income was allocated to the Series C Preferred Units, respectively. For the three and nine months ended September 30, 2017 , $0.7 million of income was allocated to the Series C Preferred Units.

(d) Common Unit Distributions

Unless restricted by the terms of our credit facility and/or the indentures governing our senior unsecured notes, we must make distributions of 100% of available cash, as defined in our partnership agreement, within 45 days following the end of each quarter. Distributions of available cash are made to our general partner in accordance with its current percentage interest with the remainder to the common unitholders, subject to the payment of incentive distributions as described below to the extent that certain target levels of cash distributions are achieved. The general partner is not entitled to incentive distributions with respect to (i) distributions on the Series B Preferred Units until such units convert into common units or (ii) the Series C Preferred Units.

Our general partner owns the general partner interest in us and all incentive distribution rights. Our general partner is entitled to receive incentive distributions if the amount we distribute with respect to any quarter exceeds levels specified in the partnership agreement. Under the quarterly incentive distribution provisions, our general partner is entitled to 13.0% of amounts we distribute in excess of $0.25 per unit, 23.0% of the amounts we distribute in excess of $0.3125 per unit, and 48.0% of amounts we distribute in excess of $0.375 per unit.

A summary of the distribution activity relating to the common units during the nine months ended September 30, 2018 and 2017 is provided below:

Declaration period	Distribution/unit		Date paid/payable
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
2017			
Fourth Quarter of 2016	$	0.39	February 13, 2017
First Quarter of 2017	$	0.39	May 12, 2017
Second Quarter of 2017	$	0.39	August 11, 2017
Third Quarter of 2017	$	0.39	November 13, 2017

(e) Earnings Per Unit and Dilution Computations

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2018	2017	2018	2017
Limited partners' interest in net income (loss)	$ 5.2	$ (8.6)	$ 85.7	$ (18.4)
Distributed earnings allocated to:				
Common units (1)(2)	$ 137.3	$ 135.7	$ 410.4	$ 405.0
Unvested restricted units (1)(2)	1.2	1.1	3.1	3.0
Total distributed earnings	$ 138.5	$ 136.8	$ 413.5	$ 408.0
Undistributed loss allocated to:				
Common units	$ (132.2)	$ (144.3)	$ (325.3)	$ (423.3)
Unvested restricted units	(1.1)	(1.1)	(2.5)	(3.1)
Total undistributed loss	$ (133.3)	$ (145.4)	$ (327.8)	$ (426.4)
Net income (loss) allocated to:				
Common units	$ 5.1	$ (8.6)	$ 85.1	$ (18.3)
Unvested restricted units	0.1	—	0.6	(0.1)
Total limited partners' interest in net income (loss)	$ 5.2	$ (8.6)	$ 85.7	$ (18.4)
Basic and diluted net income (loss) per unit:				
Basic	$ 0.01	$ (0.02)	$ 0.24	$ (0.05)
Diluted	$ 0.01	$ (0.02)	$ 0.24	$ (0.05)

(1) For the three months ended September 30, 2018 and 2017 , distributed earnings represent a declared distribution of $0.39 per unit payable on November 13, 2018 and a distribution of $0.39 per unit paid on November 13, 2017 , respectively.
(2) For the nine months ended September 30, 2018 , distributed earnings included a declared distribution of $0.39 per unit payable on November 13, 2018 , $0.39 per unit paid on August 13, 2018 , and $0.39 per unit paid on May 14, 2018 . For the nine months ended September 30, 2017 , distributed earnings included distributions of $0.39 per unit paid on November 13, 2017 , $0.39 per unit paid on August 11, 2017 , and $0.39 per unit paid on May 12, 2017 .

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2018	2017	2018	2017
Basic weighted average units outstanding:				
Weighted average limited partner basic common units outstanding	351.9	347.9	350.7	346.1
Diluted weighted average units outstanding:				
Weighted average limited partner basic common units outstanding	351.9	347.9	350.7	346.1
Dilutive effect of non-vested restricted units (1)	1.6	—	1.5	—
Total weighted average limited partner diluted common units outstanding	353.5	347.9	352.2	346.1

(1) All common unit equivalents were antidilutive for the three and nine months ended September 30, 2017 because the limited partners were allocated a net loss. The Series B Preferred Units were also antidilutive for the three and nine months ended September 30, 2018 and 2017 .

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

Net income is allocated to our general partner in an amount equal to its incentive distribution rights as described in section "(d) Common Unit Distributions" above. Our general partner's share of net income consists 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,	
	2018	2017	2018	2017
Income allocation for incentive distributions	$ 15.0	$ 14.8	$ 44.6	$ 44.1
Unit-based compensation attributable to ENLC's restricted and performance units	(7.3)	(4.2)	(15.7)	(16.9)
General partner share of net income	—	—	0.6	0.1
General partner interest in net income	$ 7.7	$ 10.6	$ 29.5	$ 27.3

(7) Investment in Unconsolidated Affiliates

As of September 30, 2018 , our unconsolidated investments consisted of a 38.75% ownership in GCF and an approximate 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,	
	2018	2017	2018	2017
GCF				
Distributions	$ 5.3	$ 3.5	$ 16.4	$ 10.6
Equity in income	$ 4.6	$ 4.5	$ 14.0	$ 8.5
HEP				
Equity in loss (1)	$ —	$ —	$ —	$ (3.4)
Cedar Cove JV				
Contributions	$ —	$ 1.5	$ 0.1	$ 11.8
Distributions	$ —	$ 0.5	$ 0.3	$ 0.8
Equity in loss	$ (0.3)	$ (0.1)	$ (2.3)	$ (0.1)
Total				
Contributions	$ —	$ 1.5	$ 0.1	$ 11.8
Distributions	$ 5.3	$ 4.0	$ 16.7	$ 11.4
Equity in income (1)	$ 4.3	$ 4.4	$ 11.7	$ 5.0

(1) We sold our ownership interest in HEP during the first quarter of 2017 , resulting in a loss of $3.4 million for the nine months ended September 30, 2017 .

The following table shows the balances related to our investment in unconsolidated affiliates as of September 30, 2018 and December 31, 2017 (in millions):

	September 30, 2018	December 31, 2017
GCF	$ 46.0	$ 48.4
Cedar Cove JV	38.5	41.0
Total investment in unconsolidated affiliates	$ 84.5	$ 89.4

(8) Employee Incentive Plans

(a) Long-Term Incentive Plans

We and ENLC each have similar unit-based compensation payment plans for officers and employees. We grant unit-based awards under the amended and restated EnLink Midstream GP, LLC Long-Term Incentive Plan (the "GP Plan") , and ENLC grants unit-based awards under the EnLink Midstream, LLC 2014 Long-Term Incentive Plan (the "2014 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 interests in us and EOGP. 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,	
	2018	2017	2018	2017
Cost of unit-based compensation charged to operating expense	$ 5.2	$ 2.8	$ 9.5	$ 10.4
Cost of unit-based compensation charged to general and administrative expense	11.8	7.3	22.1	28.3
Total unit-based compensation expense	$ 17.0	$ 10.1	$ 31.6	$ 38.7

(b) EnLink Midstream Partners, LP Restricted Incentive Units

ENLK restricted incentive units are 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, 2018 is provided below:

	Nine Months Ended September 30, 2018	
EnLink Midstream Partners, LP Restricted Incentive Units:	**Number of Units**	**Weighted Average Grant-Date Fair Value**
Non-vested, beginning of period	1,980,224	$ 15.81
Granted (1)	1,586,750	15.27
Vested (1)(2)	(813,290)	19.78
Forfeited	(157,057)	12.42
Non-vested, end of period	2,596,627	$ 14.44
Aggregate intrinsic value, end of period (in millions)	$ 48.4	

(1) Restricted incentive units typically vest at the end of three years. In March 2018, we granted 200,753 restricted incentive units with a fair value of $3.0 million to officers and certain employees as bonus payments for 2017, and these restricted incentive units vested immediately and are included in the restricted incentive units granted and vested line items.
(2) Vested units included 255,653 units withheld for payroll taxes paid on behalf of employees.

A summary of the restricted incentive units' aggregate intrinsic value (market value at vesting date) and fair value of units vested (market value at date of grant) for the three and nine months ended September 30, 2018 and 2017 is provided below (in millions):

	Three Months Ended September 30,		Nine Months Ended September 30,	
EnLink Midstream Partners, LP Restricted Incentive Units:	**2018**	**2017**	**2018**	**2017**
Aggregate intrinsic value of units vested	$ 3.7	$ 0.6	$ 12.8	$ 16.3
Fair value of units vested	$ 2.8	$ 1.1	$ 16.1	$ 22.1

As of September 30, 2018 , there was $22.2 million of unrecognized compensation cost related to non-vested ENLK restricted incentive units. That cost is expected to be recognized over a weighted-average period of 2.0 years .

(c) EnLink Midstream Partners, LP Performance Units

Our general partner grants performance awards under the GP 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 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 contemplate that the Peer Companies for an individual performance award (the "Subject Award") are the companies comprising the AMZ, excluding ENLK and ENLC, on the grant date for the Subject Award. The performance units will vest based on the percentile ranking of the 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.

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 EnLink TSR as compared to the TSR of the Peer Companies on the vesting date. The fair value of each performance unit is estimated as of the date of grant using a Monte Carlo simulation with the following assumptions used for all performance unit grants made under the plan: (i) a risk-free interest rate based on United States Treasury rates as of the grant date; (ii) a volatility assumption based on the historical realized price volatility of our common units and the designated Peer Companies' securities; (iii) an estimated ranking of us among the designated Peer Companies; and (iv) the distribution yield. 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 of performance units granted and the related assumptions by performance unit grant date:

EnLink Midstream Partners, LP Performance Units:	**March 2018**
Beginning TSR price	$ 15.44
Risk-free interest rate	2.38%
Volatility factor	43.85%
Distribution yield	10.5%

ENLINK MIDSTREAM PARTNERS, LP
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The following table presents a summary of the performance units:

	Nine Months Ended September 30, 2018	
EnLink Midstream Partners, LP Performance Units:	**Number of Units**	**Weighted Average Grant-Date Fair Value**
Non-vested, beginning of period	585,285	$ 20.52
Granted	256,345	19.24
Vested (1)	(313,610)	24.43
Forfeited	(76,351)	16.62
Non-vested, end of period	451,669	$ 17.74
Aggregate intrinsic value, end of period (in millions)	$ 8.4	

(1) Vested units included 112,101 units withheld for payroll taxes paid on behalf of employees and 120,250 units that vested as a result of the GIP Transaction, net of units withheld for payroll taxes.

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 nine months ended September 30, 2018 is provided below (in millions). No performance units vested for the three and nine months ended September 30, 2017 .

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

As of September 30, 2018 , there was $6.2 million of unrecognized compensation cost that related to non-vested ENLK performance units. That cost is expected to be recognized over a weighted-average period of 1.8 years .

In connection with the GIP Transaction, certain outstanding performance unit agreements were modified to increase the minimum vesting of units from zero to 100% as described in our Current Report on Form 8-K filed with the Securities and Exchange Commission (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 $2.3 million compensation cost over the life of these ENLK performance units.

(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, 2018 is provided below:

	Nine Months Ended September 30, 2018	
EnLink Midstream, LLC Restricted Incentive Units:	**Number of Units**	**Weighted Average Grant-Date Fair Value**
Non-vested, beginning of period	1,889,310	$ 16.33
Granted (1)	1,469,452	15.76
Vested (1)(2)	(749,164)	21.53
Forfeited	(146,045)	12.38
Non-vested, end of period	2,463,553	$ 14.64
Aggregate intrinsic value, end of period (in millions)	$ 40.5	

(1) Restricted incentive units typically vest at the end of three years. In March 2018, ENLC granted 194,185 restricted incentive units with a fair value of $3.0 million to officers and certain employees as bonus payments for 2017, and these restricted incentive units vested immediately and are included in the restricted incentive units granted and vested line items.
(2) Vested units included 238,970 units withheld for payroll taxes paid on behalf of employees .

A summary of the restricted incentive units' aggregate intrinsic value (market value at vesting date) and fair value of units vested (market value at date of grant) for the three and nine months ended September 30, 2018 and 2017 is provided below (in millions):

	Three Months Ended September 30,		Nine Months Ended September 30,	
EnLink Midstream, LLC Restricted Incentive Units:	**2018**	**2017**	**2018**	**2017**
Aggregate intrinsic value of units vested	$ 3.3	$ 0.6	$ 12.6	$ 15.2
Fair value of units vested	$ 2.6	$ 1.1	$ 16.1	$ 21.9

As of September 30, 2018 , there was $21.5 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 2.0 years .

(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 TSR performance goals relative to the TSR achievement of the Peer Companies 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 EnLink TSR as compared to the TSR of the Peer Companies on the vesting date. The fair value of each performance unit is estimated as of the date of grant using a Monte Carlo simulation with the following assumptions used for all performance unit grants made under the plan: (i) a risk-free interest rate based on United States Treasury rates as of the grant date; (ii) a volatility assumption based on the historical realized price volatility of ENLC's common units and the designated Peer Companies' securities; (iii) an estimated ranking of 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 grant-date fair value assumptions by performance unit grant date:

EnLink Midstream, LLC Performance Units:	March 2018
Beginning TSR price	$ 16.55
Risk-free interest rate	2.38%
Volatility factor	51.36%
Distribution yield	6.7%

The following table presents a summary of the performance units:

	Nine Months Ended September 30, 2018	
EnLink Midstream, LLC Performance Units:	Number of Units	Weighted Average Grant-Date Fair Value
Non-vested, beginning of period	548,839	$ 22.14
Granted	223,865	21.63
Vested (1)	(283,637)	27.25
Forfeited	(70,918)	17.75
Non-vested, end of period	418,149	$ 19.15
Aggregate intrinsic value, end of period (in millions)	$ 6.9	

(1) Vested units included 100,109 units withheld for payroll taxes paid on behalf of employees and 109,819 units that vested as a result of the GIP Transaction, net of units withheld for payroll taxes.

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 nine months ended September 30, 2018 is provided below (in millions). No performance units vested for the three and nine months ended September 30, 2017 .

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

As of September 30, 2018 , there was $6.0 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 1.8 years .

In connection with the GIP Transaction, certain outstanding performance unit agreements were modified to 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 c ompensation cost over the life of these ENLC performance units.

(9) Derivatives

Interest Rate Swaps

We periodically enter into interest rate swaps in connection with new debt issuances. During the debt issuance process, we are exposed to 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. In order to hedge this variability, we enter into interest rate swaps to effectively lock in the benchmark interest rate at the inception of the swap. Prior to 2017, we did not designate interest rate swaps as hedges and, therefore, included the associated settlement gains and losses as interest expense, net of interest income on the consolidated statements of operations.

In May 2017, we entered into an interest rate swap in connection with the issuance of our 5.45% senior unsecured notes due 2047 (the “2047 Notes”). In accordance with ASC 815, we designated this swap as a cash flow hedge. 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, 2018 , we amortized an immaterial amount of the settlement loss into interest expense from accumulated other comprehensive income (loss). We expect to recognize $0.1 million of interest expense out of accumulated other comprehensive income (loss) over the next twelve months. We have no open interest rate swap position as of September 30, 2018 .

Commodity Swaps

We manage our exposure to changes in commodity prices by hedging the impact of market fluctuations. Commodity swaps are used both to manage and hedge price and location risk related to these market exposures and to manage margins on offsetting fixed-price purchase or sale commitments for physical quantities of crude, condensate, natural gas, and NGLs. We do not designate commodity swaps as cash flow or fair value hedges for hedge accounting treatment under ASC 815. Therefore, changes in the fair value of our derivatives are recorded in revenue in the period incurred. In addition, our commodity risk management policy does not allow us to take speculative positions with our derivative contracts.

We commonly enter into index (float-for-float) or fixed-for-float swaps in order to mitigate our cash flow exposure to fluctuations in the future prices of natural gas, NGLs, and crude oil. For natural gas, index swaps are used to protect against the price exposure of daily priced gas versus first-of-month priced gas. They are also used to hedge the basis location price risk resulting from supply and markets being priced on different indices. For natural gas, NGLs, condensate, and crude oil, fixed-for-float swaps are used to protect cash flows against price fluctuations: (1) where we receive a percentage of liquids as a fee for processing third-party gas or where we receive a portion of the proceeds of the sales of natural gas and liquids as a fee, (2) in the natural gas processing and fractionation components of our business and (3) where we are mitigating the price risk for product held in inventory or storage.

Assets and liabilities related to our derivative contracts are included in the fair value of derivative assets and liabilities, and the change in fair value of these contracts is recorded net as a gain (loss) on derivative activity on the consolidated statements of operations. We estimate the fair value of all of our derivative contracts based upon actively-quoted prices of the underlying commodities.

The components of 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,	
	2018	2017	2018	2017
Change in fair value of derivatives	$ (0.8)	$ (3.3)	$ (14.8)	$ 3.8
Realized loss on derivatives	(4.6)	(2.2)	(5.3)	(4.9)
Loss on derivative activity	$ (5.4)	$ (5.5)	$ (20.1)	$ (1.1)

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

	September 30, 2018	December 31, 2017
Fair value of derivative assets—current	$ 12.5	$ 6.8
Fair value of derivative liabilities—current	(21.9)	(8.4)
Fair value of derivative liabilities—long-term	(7.0)	—
Net fair value of derivatives	$ (16.4)	$ (1.6)

As of September 30, 2018 and December 31, 2017 , there were no derivative assets classified as long-term on the consolidated balance sheets.

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, 2018 (in millions). The remaining term of the contracts extend no later than December 2022.

		September 30, 2018		
Commodity	Instruments	Unit	Volume	Fair Value
NGL (short contracts)	Swaps	Gallons	(58.4)	$ (12.0)
NGL (long contracts)	Swaps	Gallons	18.9	3.1
Natural Gas (short contracts)	Swaps	MMBtu	(9.0)	0.4
Natural Gas (long contracts)	Swaps	MMBtu	10.9	(1.4)
Crude and condensate (short contracts)	Swaps	MMbbls	(13.3)	(13.2)
Crude and condensate (long contracts)	Swaps	MMbbls	1.3	6.7
Total fair value of derivatives				$ (16.4)

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 $12.5 million as of September 30, 2018 would be reduced to $0.1 million due to the offsetting of gross fair value payables against gross fair value receivables as allowed by the ISDAs.

(10) Fair Value Measurements

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

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

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

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

	Level 2	
	September 30, 2018	December 31, 2017
Commodity Swaps (1)	$ (16.4)	$ (1.6)

(1) The fair values of derivative contracts included in assets or liabilities for risk management activities 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, 2018		December 31, 2017	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Long-term debt, including current maturities of long-term debt (1)	$ 4,235.5	$ 4,017.6	$ 3,467.8	$ 3,575.6
Installment Payables	$ —	$ —	$ 249.5	$ 249.6
Obligations under capital lease	$ 2.9	$ 2.5	$ 4.1	$ 3.4
Secured term loan receivable	$ 49.9	$ 49.9	$ —	$ —

(1) The carrying value of long-term debt, including current maturities of long-term debt, is reduced by debt issuance costs of $23.4 million and $25.9 million at September 30, 2018 and December 31, 2017 , respectively. The respective fair values do not factor in debt issuance costs.

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

We had $765.0 million of outstanding borrowings under our credit facility as of September 30, 2018 and no outstanding borrowings under our credit facility as of December 31, 2017 . As borrowings under our credit facility accrue interest under floating interest rate structures, the carrying value of such indebtedness approximates fair value for the amounts outstanding under our credit facility. As of September 30, 2018 and December 31, 2017 , we had total borrowings under senior unsecured notes of $3.5 billion maturing between 2019 and 2047 with fixed interest rates ranging from 2.7% to 5.6% .

The fair values of all senior unsecured notes and installment payables as of September 30, 2018 and December 31, 2017 were based on Level 2 inputs from third-party market quotations. The fair values of obligations under capital leases and the secured term loan receivable were calculated using Level 2 inputs from third-party banks.

(11) Segment Information

Identification of the majority of our operating segments is based principally upon geographic regions served and the nature of operating activity. Our reportable segments consist of the following: natural gas gathering, processing, transmission, and fractionation operations located in North Texas and the Permian Basin primarily in West Texas ("Texas"), natural gas pipelines, processing plants, storage facilities, NGL pipelines, and fractionation assets in Louisiana ("Louisiana"), natural gas gathering and processing operations located throughout Oklahoma ("Oklahoma"), and crude rail, truck, pipeline, and barge facilities in West Texas, South Texas, Louisiana, Oklahoma, and the Ohio River Valley ("Crude and Condensate"). Operating activity for intersegment eliminations is shown in the Corporate segment. Our sales are derived from external domestic customers. We evaluate the performance of our operating segments based on segment profits.

Corporate assets consist primarily of cash, property, and equipment, including software, for general corporate support, debt financing costs, and unconsolidated affiliate investments in GCF and the Cedar Cove JV.

Based on the disclosure requirements of ASC 606, we are presenting revenues disaggregated based on the type of good or service in order to more fully depict the nature of our revenues . As we adopted ASC 606 using the modified retrospective method, only the consolidated statement of operations and revenue disaggregation information for the three and nine months ended September 30, 2018 are presented to conform to ASC 606 accounting and disclosure requirements. Prior periods presented in the consolidated financial statements and accompanying notes were not restated in accordance with ASC 606.

ENLINK MIDSTREAM PARTNERS, LP
Notes to Consolidated Financial Statements (Continued)
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Summarized financial information for our reportable segments is shown in the following tables (in millions):

	Texas	Louisiana	Oklahoma	Crude and Condensate	Corporate	Totals
Three Months Ended September 30, 2018						
Natural gas sales	$ 69.1	$ 129.5	$ 41.9	$ —	$ —	$ 240.5
NGL sales	16.8	839.6	12.8	0.1	—	869.3
Crude oil and condensate sales	—	0.1	0.3	722.0	—	722.4
Product sales	85.9	969.2	55.0	722.1	—	1,832.2
Natural gas sales—related parties	—	—	0.1	—	—	0.1
NGL sales—related parties	153.8	10.9	192.5	—	(347.2)	10.0
Crude oil and condensate sales—related parties	13.4	0.1	18.0	1.5	(32.9)	0.1
Product sales—related parties	167.2	11.0	210.6	1.5	(380.1)	10.2
Gathering and transportation	71.7	17.5	50.2	0.8	—	140.2
Processing	39.4	0.8	31.5	—	—	71.7
NGL services	—	11.9	—	—	—	11.9
Crude services	—	—	0.2	14.9	—	15.1
Other services	2.4	0.1	—	0.1	—	2.6
Midstream services	113.5	30.3	81.9	15.8	—	241.5
Gathering and transportation—related parties	8.7	—	7.2	—	—	15.9
Processing—related parties	10.2	—	3.2	—	—	13.4
Crude services—related parties	—	—	0.1	6.3	—	6.4
Other services—related parties	0.1	—	—	—	—	0.1
Midstream services—related parties	19.0	—	10.5	6.3	—	35.8
Revenue from contracts with customers	385.6	1,010.5	358.0	745.7	(380.1)	2,119.7
Cost of sales	(222.0)	(923.6)	(228.5)	(702.6)	380.1	(1,696.6)
Operating expenses	(44.7)	(28.7)	(22.5)	(18.8)	—	(114.7)
Loss on derivative activity	—	—	—	—	(5.4)	(5.4)
Segment profit (loss)	$ 118.9	$ 58.2	$ 107.0	$ 24.3	$ (5.4)	$ 303.0
Depreciation and amortization	$ (54.0)	$ (32.7)	$ (44.7)	$ (12.9)	$ (2.4)	$ (146.7)
Impairments	$ —	$ (24.6)	$ —	$ —	$ —	$ (24.6)
Goodwill	$ 232.0	$ —	$ 190.3	$ —	$ —	$ 422.3
Capital expenditures	$ 90.0	$ 13.0	$ 109.3	$ 39.9	$ 1.1	$ 253.3
Three Months Ended September 30, 2017						
Product sales	$ 80.8	$ 642.3	$ 42.5	$ 291.1	$ —	$ 1,056.7
Product sales—related parties	130.6	10.0	94.6	—	(199.9)	35.3
Midstream services	29.1	50.3	44.3	12.7	—	136.4
Midstream services—related parties	106.7	35.9	63.0	4.8	(35.4)	175.0
Cost of sales	(198.5)	(662.7)	(148.2)	(279.1)	235.3	(1,053.2)
Operating expenses	(41.1)	(24.8)	(17.1)	(19.1)	—	(102.1)
Loss on derivative activity	—	—	—	—	(5.5)	(5.5)
Segment profit (loss)	$ 107.6	$ 51.0	$ 79.1	$ 10.4	$ (5.5)	$ 242.6
Depreciation and amortization	$ (52.5)	$ (29.3)	$ (40.2)	$ (11.7)	$ (2.6)	$ (136.3)
Impairments	$ —	$ —	$ —	$ (1.8)	$ —	$ (1.8)
Goodwill	$ 232.0	$ —	$ 190.3	$ —	$ —	$ 422.3
Capital expenditures	$ 39.1	$ 7.5	$ 107.7	$ 13.3	$ 2.1	$ 169.7

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

	Texas	Louisiana	Oklahoma	Crude and Condensate	Corporate	Totals
Nine Months Ended September 30, 2018						
Natural gas sales	$ 208.9	$ 377.2	$ 127.9	$ —	$ —	$ 714.0
NGL sales	16.8	2,075.9	18.3	0.9	—	2,111.9
Crude oil and condensate sales	—	0.2	0.3	1,940.1	—	1,940.6
Product sales	225.7	2,453.3	146.5	1,941.0	—	4,766.5
Natural gas sales—related parties	—	—	2.5	—	—	2.5
NGL sales—related parties	381.1	45.4	433.0	—	(822.1)	37.4
Crude oil and condensate sales—related parties	39.4	0.3	63.9	3.3	(105.8)	1.1
Product sales—related parties	420.5	45.7	499.4	3.3	(927.9)	41.0
Gathering and transportation	98.4	51.8	91.4	2.5	—	244.1
Processing	52.7	2.5	87.9	—	—	143.1
NGL services	—	38.8	—	—	—	38.8
Crude services	—	—	0.2	42.8	—	43.0
Other services	6.4	0.5	—	0.2	—	7.1
Midstream services	157.5	93.6	179.5	45.5	—	476.1
Gathering and transportation—related parties	122.7	—	80.6	—	—	203.3
Processing—related parties	108.6	—	48.4	—	—	157.0
Crude services—related parties	—	—	1.5	14.9	—	16.4
Other services—related parties	0.5	—	—	—	—	0.5
Midstream services—related parties	231.8	—	130.5	14.9	—	377.2
Revenue from contracts with customers	1,035.5	2,592.6	955.9	2,004.7	(927.9)	5,660.8
Cost of sales	(562.2)	(2,333.3)	(537.8)	(1,898.3)	927.9	(4,403.7)
Operating expenses	(134.7)	(82.3)	(64.0)	(56.3)	—	(337.3)
Loss on derivative activity	—	—	—	—	(20.1)	(20.1)
Segment profit (loss)	$ 338.6	$ 177.0	$ 354.1	$ 50.1	$ (20.1)	$ 899.7
Depreciation and amortization	$ (159.9)	$ (92.4)	$ (133.2)	$ (38.0)	$ (6.6)	$ (430.1)
Impairments	$ —	$ (24.6)	$ —	$ —	$ —	$ (24.6)
Goodwill	$ 232.0	$ —	$ 190.3	$ —	$ —	$ 422.3
Capital expenditures	$ 200.0	$ 36.4	$ 328.8	$ 84.1	$ 3.4	$ 652.7
Nine Months Ended September 30, 2017						
Product sales	$ 240.5	$ 1,735.5	$ 84.7	$ 913.2	$ —	$ 2,973.9
Product sales—related parties	352.6	25.6	221.4	0.8	(493.1)	107.3
Midstream services	85.1	159.7	105.2	45.7	—	395.7
Midstream services—related parties	319.0	100.2	171.8	13.4	(96.8)	507.6
Cost of sales	(554.7)	(1,803.1)	(335.9)	(884.1)	589.9	(2,987.9)
Operating expenses	(127.9)	(74.8)	(45.9)	(60.2)	—	(308.8)
Loss on derivative activity	—	—	—	—	(1.1)	(1.1)
Segment profit (loss)	$ 314.6	$ 143.1	$ 201.3	$ 28.8	$ (1.1)	$ 686.7
Depreciation and amortization	$ (161.9)	$ (86.8)	$ (115.3)	$ (35.8)	$ (7.3)	$ (407.1)
Impairments	$ —	$ —	$ —	$ (8.8)	$ —	$ (8.8)
Goodwill	$ 232.0	$ —	$ 190.3	$ —	$ —	$ 422.3
Capital expenditures	$ 107.1	$ 55.8	$ 383.4	$ 64.4	$ 25.6	$ 636.3

The table below represents information about segment assets as of September 30, 2018 and December 31, 2017 (in millions):

Segment Identifiable Assets:	September 30, 2018	December 31, 2017
Texas	$ 3,161.9	$ 3,094.8
Louisiana	2,583.8	2,408.5
Oklahoma	3,074.1	2,836.7
Crude and Condensate	1,069.9	929.5
Corporate	183.9	144.5
Total identifiable assets	$ 10,073.6	$ 9,414.0

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,	
	2018	2017	2018	2017
Segment profit	$ 303.0	$ 242.6	$ 899.7	$ 686.7
General and administrative expenses	(39.2)	(30.0)	(94.5)	(94.6)
Loss on disposition of assets	—	(1.1)	(1.3)	(0.8)
Depreciation and amortization	(146.7)	(136.3)	(430.1)	(407.1)
Impairments	(24.6)	(1.8)	(24.6)	(8.8)
Gain on litigation settlement	—	—	—	26.0
Operating income	$ 92.5	$ 73.4	$ 349.2	$ 201.4

(12) Other Information

The following tables present additional detail for other current assets and other current liabilities, which consists of the following (in millions):

Other Current Assets:	September 30, 2018	December 31, 2017
Natural gas and NGLs inventory	$ 119.4	$ 30.1
Secured term loan receivable from contract restructuring, net of discount o f $1.1	18.4	—
Prepaid expenses and other	15.6	9.6
Natural gas and NGLs inventory, prepaid expenses, and other	$ 153.4	$ 39.7

Other Current Liabilities:	September 30, 2018	December 31, 2017
Accrued interest	$ 64.5	$ 35.4
Accrued wages and benefits, including taxes	24.8	30.4
Accrued ad valorem taxes	33.4	27.8
Capital expenditure accruals	57.9	48.8
Onerous performance obligations	13.5	15.2
Other	65.7	64.8
Other current liabilities	$ 259.8	$ 222.4

(13) Subsequent Event

On October 21, 2018, we and ENLC entered into the Merger Agreement and the related preferred restructuring agreement, pursuant to which, subject to the satisfaction or waiver of certain conditions:

- Each issued and outstanding ENLK common unit (except for ENLK common units held by ENLC and its subsidiaries) will be converted into the right to receive 1.15 ENLC common units;
- Our general partner's incentive distribution rights in ENLK will be eliminated;
- The Series B Preferred Units will continue to be issued and outstanding following the Merger, except that certain terms of the Series B Preferred Units will be modified pursuant to an amended partnership agreement of ENLK, including exchangeability of the Series B Preferred Units, under certain circumstances, into ENLC common units instead of ENLK common units, subject to the election of ENLK to instead redeem for cash any such exchanged Series B Preferred Units;
- ENLC will issue to Enfield Holdings, L.P. ("Enfield"), the current holder of the Series B Preferred Units, for no additional consideration, a new class of non-economic ENLC 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;
- The Series C Preferred Units will continue to be issued and outstanding following the Merger; and
- All unit-based awards issued and outstanding immediately prior to the effective time of the Merger under the GP Plan will be converted into an award with respect to ENLC common units with substantially similar terms as were in effect immediately prior to the effective time, with certain adjustments to the performance-based vesting of terms of applicable awards related to the performance of ENLC.

The Merger Transactions are expected to close in the first quarter of 2019, subject to obtaining approval of our unitholders, customary regulatory approvals, and other customary closing conditions.

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 11,000 miles of pipelines, 20 natural gas processing plants with approximately 4.8 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:

- *Texas Segment* . The Texas segment includes our natural gas gathering, processing, and transmission operations in North Texas and the Permian Basin primarily in West Texas;

- *Oklahoma Segment* . The Oklahoma segment includes our natural gas gathering, processing, and transmission activities in the Cana-Woodford, Arkoma-Woodford, Northern Oklahoma Woodford, STACK, and CNOW 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;

- *Crude and Condensate Segment* . The Crude and Condensate segment includes our ORV crude oil, condensate, condensate stabilization, natural gas compression, and brine disposal activities in the Utica and Marcellus Shales, our crude oil operations in the Permian Basin, Delaware Basin, and Central Oklahoma, and our crude oil activities associated with VEX located in the Eagle Ford Shale; and

- *Corporate Segment* . The Corporate segment includes our unconsolidated affiliate investments in the Cedar Cove JV in Oklahoma, our ownership interest in GCF in South Texas, and our general corporate property 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, 2018 . 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, 2018 , approximately 38.5% and 38.3% of our gross operating margin, respectively, was attributable to commercial contracts with Devon.

We generate revenues 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.

Our gross operating margins are determined primarily by the volumes of:

- natural gas gathered, transported, purchased, and sold through our pipeline systems;
- natural gas processed at our processing facilities;
- NGLs handled at our fractionation facilities or transported through our pipeline systems;
- crude oil and condensate handled at our crude terminals;
- crude oil and condensate gathered, transported, purchased, and sold;
- condensate stabilized;
- brine disposed; and
- natural gas, crude oil, and NGLs stored.

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.

On occasion we have entered into certain purchase/sale transactions in which the purchase price is based on a production-area index and the sales price is based on a market-area index, and we capture the difference in the indices (also referred to as “basis spread”), less the transportation expenses from the two areas, as our fee. Changes in the basis spread can increase or decrease our margins or potentially result in losses. For example, we are a party to one contract associated with our North Texas operations with a term ending June 2019 that requires us to supply approximately 150,000 MMBtu/d of gas. We buy gas for this contract on several different production-area indices and sell the gas into a different market-area index. We realize a cash loss on the delivery of gas under this contract each month based on current prices. The fair value of this performance obligation was recorded based on forecasted discounted cash obligations in excess of market prices under this gas delivery contract. As of September 30, 2018 , the balance sheet reflects a liability of $13.5 million related to this performance obligation. Unfavorable basis spreads in recent periods have increased the losses on this contract, and greater losses on this contract could occur in future periods if these conditions persist or become worse.

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 from producers at a market index less a stated deduction, then transport and resell the crude oil and condensate at the same market index. 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 at its sole discretion.

Recent Developments

Simplification of Corporate Structure. On October 21, 2018, we, ENLC, our general partner, the managing member of ENLC , and NOLA Merger Sub, LLC, a wholly-owned subsidiary of ENLC ("NOLA Merger Sub"), entered into a definitive agreement and plan of merger (the "Merger Agreement") pursuant to which, subject to the satisfaction or waiver of certain conditions in the Merger Agreement, NOLA Merger Sub will merge with and into ENLK (the "Merger"), with ENLK continuing as the surviving entity and a subsidiary of ENLC. The Merger and the other transactions contemplated by the Merger Agreement and the preferred restructuring agreement entered into concurrently with the Merger Agreement (the "Merger Transactions") are expected to close in the first quarter of 2019, subject to obtaining our unitholder approval, customary regulatory approvals, and other customary closing conditions. See "Item 1. Financial Statements—Note 13—Subsequent Event " for more information regarding this transaction.

Strategic Partner Update. On July 18, 2018, subsidiaries of Devon closed a transaction to sell all of their equity interests in ENLK, ENLC, and ENLC's managing member to GIP. See "Item 1. Financial Statements— Note 1—General " for more information regarding the GIP Transaction.

Cajun-Sibon Pipeline. We commenced an 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 will increase throughput capacity from 130,000 bbls/d to 185,000 bbls/d. We expect Cajun-Sibon III to be operational during the second quarter of 2019.

Avenger Crude Oil Gathering System. We are constructing a new crude oil gathering system in the northern Delaware Basin called the Avenger crude oil gathering system ("Avenger"). Avenger is wholly owned by ENLK and 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 expect to begin full-service operations during the first half of 2019.

Central Oklahoma Plants. In December 2017, we commenced construction on an additional 200 MMcf/d gas processing plant, referred to as the "Thunderbird plant" to expand our Central Oklahoma processing capacity. We expect to begin operations on the Thunderbird plant during the first quarter of 2019.

Central Oklahoma Crude Oil Gathering Systems. In late March 2018, we completed construction of the first phase of a new crude oil gathering system that we refer to as "Black Coyote." Black Coyote expands our operations in the core of the STACK play in Central Oklahoma and was built primarily on acreage dedicated from Devon, which is the main shipper on the system. In addition, we are further expanding our crude oil gathering operations in the STACK through the construction of the Redbud Crude Oil Gathering System ("Redbud"), which is supported by a contract with an existing large and active customer in the STACK. We commenced initial operations on Redbud during the third quarter of 2018. Both Black Coyote and Redbud are jointly owned by ENLK and ENLC through their respective ownership in EOGP.

Lobo Natural Gas Gathering and Processing Facilities. During the second quarter of 2018, we completed construction of an expansion to our Lobo II cryogenic gas processing plant, bringing total operational processing capacity at our Lobo facilities to 175 MMcf/d. We are further expanding our gas processing capacity at our Lobo facilities through the construction of the Lobo III cryogenic gas processing plant. We expect 100 MMcf/d of operational capacity at Lobo III to be completed during the fourth quarter of 2018 and an additional 100 MMcf/d of operational capacity to be completed during the first quarter of 2019.

Non-GAAP Financial Measures

We include the following non-GAAP financial measures: Adjusted earnings before interest, taxes, and depreciation and amortization ("adjusted EBITDA"), distributable cash flow available to common unitholders ("distributable cash flow"), and gross operating margin.

Adjusted EBITDA

We define adjusted EBITDA as net income (loss) plus interest expense, provision (benefit) for income taxes, depreciation and amortization expense, impairments, unit-based compensation, (gain) loss on non-cash derivatives, (gain) loss on disposition of assets, (gain) loss on extinguishment of debt, successful transaction costs, accretion expense associated with asset retirement obligations, non-cash rent, and distributions from unconsolidated affiliate investments, less payments under onerous performance obligations, non-controlling interest, income (loss) from unconsolidated affiliate investments, and non-cash revenue from contract restructuring. Adjusted EBITDA is a primary metric used in our short-term incentive program for compensating employees. In addition, adjusted EBITDA is used as a supplemental liquidity and performance measure by our management and by external users of our financial statements, such as investors, commercial banks, research analysts, and others, to assess:

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

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

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

The following tables reconcile adjusted EBITDA to the most directly comparable GAAP measure for the periods indicated (in millions):

Reconciliation of net income (loss) to adjusted EBITDA

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2018	2017	2018	2017
Net income	$ 51.9	$ 28.7	$ 229.9	$ 74.7
Interest expense, net of interest income	44.1	48.9	131.5	140.5
Depreciation and amortization	146.7	136.3	430.1	407.1
Impairments	24.6	1.8	24.6	8.8
Income from unconsolidated affiliates (1)	(4.3)	(4.4)	(11.7)	(5.0)
Distributions from unconsolidated affiliates	5.3	4.0	16.7	11.4
Loss on disposition of assets	—	1.1	1.3	0.8
Gain on extinguishment of debt	—	—	—	(9.0)
Unit-based compensation	17.0	10.1	31.6	38.7
Income tax provision (benefit)	0.9	0.5	(0.2)	0.7
(Gain) loss on non-cash derivatives	0.8	3.3	14.8	(3.8)
Payments under onerous performance obligation offset to other current and long-term liabilities	(4.5)	(4.5)	(13.5)	(13.5)
Non-cash revenue from contract restructuring (2)	—	—	(45.5)	—
Other (3)	1.3	0.8	2.0	3.5
Adjusted EBITDA before non-controlling interest	$ 283.8	$ 226.6	$ 811.6	$ 654.9
Non-controlling interest share of adjusted EBITDA (4)	(16.8)	(9.8)	(43.7)	(20.8)
Adjusted EBITDA, net to ENLK	$ 267.0	$ 216.8	$ 767.9	$ 634.1

(1) Includes a loss of $3.4 million for the nine months ended September 30, 2017 from the sale of HEP in March 2017.
(2) In May 2018, we restructured a natural gas gathering and processing contract, and, as a result, recognized non-cash revenue representing the discounted present value of a secured term loan receivable. For more information, see "Item 1. Financial Statements— Note 2 ."
(3) Includes accretion expense associated with asset retirement obligations, non-cash rent, which relates to lease incentives pro-rated over the lease term, and transaction costs, primarily associated with costs we incurred related to the GIP Transaction.
(4) Non-controlling interest share of adjusted EBITDA includes ENLC's 16.1% share of adjusted EBITDA from EOGP, NGP's 49.9% share of adjusted EBITDA from the Delaware Basin JV, Marathon Petroleum Corporation's 50% share of adjusted EBITDA from the Ascension JV, and other minor non-controlling interests.

Distributable Cash Flow

We define distributable cash flow as adjusted EBITDA, net to ENLK, less interest expense (excluding amortization of the EOGP acquisition installment payable discount), litigation settlement adjustment, interest rate swaps, current income taxes and other non-distributable cash flows, accrued cash distributions on Series B Preferred Units and Series C Preferred Units paid or expected to be paid, and maintenance capital expenditures, excluding maintenance capital expenditures that were contributed by other entities and relate to the non-controlling interest share of our consolidated entities. Distributable cash flow is used as a supplemental liquidity measure by our management and by external users of our financial statements, such as investors, commercial banks, research analysts, and others, to assess the ability of our assets to generate cash sufficient to pay interest costs, support our indebtedness, and make cash distributions to our common unitholders and our general partner.

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

The GAAP measure most directly comparable to distributable cash flow is net cash provided by operating activities. Distributable cash flow should not be considered an alternative to, or more meaningful than, net income (loss), operating income (loss), net cash provided by operating activities, or any other measure of liquidity presented in accordance with GAAP.

Distributable cash flow has important limitations because it excludes some items that affect net income (loss), operating income (loss), and net cash provided by operating activities. Distributable cash flow may not be comparable to similarly-titled measures of other companies because other companies may not calculate distributable cash flow in the same manner. To compensate for these limitations, we believe that it is important to consider net cash provided by operating activities determined under GAAP, as well as distributable cash flow, to evaluate our overall liquidity.

Reconciliation of net cash provided by operating activities to adjusted EBITDA and Distributable Cash Flow (in millions)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2018	2017	2018	2017
Net cash provided by operating activities	$ 113.1	$ 200.8	$ 543.8	$ 533.0
Interest expense (1)	44.8	41.5	130.6	118.9
Current income tax expense	1.0	0.7	1.7	0.9
Distributions from unconsolidated affiliate investment in excess of earnings	0.8	(0.1)	2.7	7.3
Other (2)	0.4	(1.7)	0.4	4.0
Changes in operating assets and liabilities which (provided) used cash:				
Accounts receivable, accrued revenues, inventories and other	298.3	127.5	385.1	105.5
Accounts payable, accrued gas and crude oil purchases and other (3)	(174.6)	(142.1)	(252.7)	(114.7)
Adjusted EBITDA before non-controlling interest	$ 283.8	$ 226.6	$ 811.6	$ 654.9
Non-controlling interest share of adjusted EBITDA (4)	(16.8)	(9.8)	(43.7)	(20.8)
Adjusted EBITDA, net to ENLK	$ 267.0	$ 216.8	$ 767.9	$ 634.1
Interest expense, net of interest income	(44.1)	(48.9)	(131.5)	(140.5)
Amortization of EOGP. installment payable discount included in interest expense (5)	—	6.4	0.5	19.9
Litigation settlement adjustment (6)	—	—	—	(18.1)
Current taxes and other	(2.1)	(0.7)	(3.3)	(0.9)
Maintenance capital expenditures, net to ENLK (7)	(11.8)	(6.9)	(30.1)	(20.5)
Preferred unit accrued cash distributions (8)	(22.4)	(16.6)	(66.9)	(16.6)
Distributable cash flow	$ 186.6	$ 150.1	$ 536.6	$ 457.4

(1) Excludes non-cash interest income and amortization of debt issuance costs and discount and premium.
(2) Includes non-cash rent, which relates to lease incentives pro-rated over the lease term, accruals for settled commodity swap transactions, and transaction costs, primarily associated with costs we incurred related to the GIP Transaction.
(3) Net of payments under onerous performance obligation offset to other current and long-term liabilities.
(4) Non-controlling interest share of adjusted EBITDA includes ENLC's 16.1% share of adjusted EBITDA from EOGP, NGP's 49.9% share of adjusted EBITDA from the Delaware Basin JV, Marathon Petroleum Corporation's 50% share of adjusted EBITDA from the Ascension JV, and other minor non-controlling interests.
(5) Amortization of the EOGP installment payable discount is considered non-cash interest under our credit facility since the payment under the payable is consideration for the acquisition of the EOGP assets.
(6) Represents recoveries from a lawsuit settled in 2017 for amounts not previously deducted from distributable cash flow.
(7) Excludes maintenance capital expenditures that were contributed by other entities and relate to the non-controlling interest share of our consolidated entities.
(8) Represents the cash distributions earned by the Series B Preferred Units and Series C Preferred Units of $16.4 million and $6.0 million , respectively, for the three months ended September 30, 2018 , $48.9 million and $18.0 million , respectively, for the nine months ended September 30, 2018 , cash distributions earned by the Series B Preferred Units of $15.9 million for the three and nine months ended September 30, 2017 , a nd cash distributions earned by the Series C Preferred Units of $0.7 million for the three and nine months ended September 30, 2017 . Cash distributions to be paid to holders of the Series B Preferred Units and Series C Preferred Units are not available to common unitholders.

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,	
	2018	2017	2018	2017
Operating income	$ 92.5	$ 73.4	$ 349.2	$ 201.4
Add (deduct):				
Operating expenses	114.7	102.1	337.3	308.8
General and administrative expenses	39.2	30.0	94.5	94.6
Loss on disposition of assets	—	1.1	1.3	0.8
Depreciation and amortization	146.7	136.3	430.1	407.1
Impairments	24.6	1.8	24.6	8.8
Gain on litigation settlement	—	—	—	(26.0)
Gross operating margin	$ 417.7	$ 344.7	$ 1,237.0	$ 995.5

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,	
	2018	2017	2018	2017
Texas Segment				
Revenues	$ 385.6	$ 347.2	$ 1,035.5	$ 997.2
Cost of sales	(222.0)	(198.5)	(562.2)	(554.7)
Total gross operating margin	$ 163.6	$ 148.7	$ 473.3	$ 442.5
Louisiana Segment				
Revenues	$ 1,010.5	$ 738.5	$ 2,592.6	$ 2,021.0
Cost of sales	(923.6)	(662.7)	(2,333.3)	(1,803.1)
Total gross operating margin	$ 86.9	$ 75.8	$ 259.3	$ 217.9
Oklahoma Segment				
Revenues	$ 358.0	$ 244.4	$ 955.9	$ 583.1
Cost of sales	(228.5)	(148.2)	(537.8)	(335.9)
Total gross operating margin	$ 129.5	$ 96.2	$ 418.1	$ 247.2
Crude and Condensate Segment				
Revenues	$ 745.7	$ 308.6	$ 2,004.7	$ 973.1
Cost of sales	(702.6)	(279.1)	(1,898.3)	(884.1)
Total gross operating margin	$ 43.1	$ 29.5	$ 106.4	$ 89.0
Corporate Segment				
Revenues	$ (385.5)	$ (240.8)	$ (948.0)	$ (591.0)
Cost of sales	380.1	235.3	927.9	589.9
Total gross operating margin	$ (5.4)	$ (5.5)	$ (20.1)	$ (1.1)
Total				
Revenues	$ 2,114.3	$ 1,397.9	$ 5,640.7	$ 3,983.4
Cost of sales	(1,696.6)	(1,053.2)	(4,403.7)	(2,987.9)
Total gross operating margin	$ 417.7	$ 344.7	$ 1,237.0	$ 995.5
Midstream Volumes:				
Texas Segment				
Gathering and Transportation (MMBtu/d)	2,267,300	2,251,700	2,237,900	2,265,900
Processing (MMBtu/d)	1,310,800	1,194,300	1,263,100	1,178,800
Louisiana Segment				
Gathering and Transportation (MMBtu/d)	2,273,700	2,009,300	2,197,100	1,960,300
Processing (MMBtu/d)	429,200	443,400	422,200	452,500
NGL Fractionation (Gals/d)	6,545,100	5,814,800	6,457,000	5,630,600
Oklahoma Segment				
Gathering and Transportation (MMBtu/d)	1,259,700	889,200	1,181,800	787,400
Processing (MMBtu/d)	1,239,000	872,200	1,170,300	753,500
Crude and Condensate Segment				
Crude Oil Handling (Bbls/d)	166,400	95,700	147,700	104,500
Brine Disposal (Bbls/d)	3,300	4,800	3,200	4,700

Three Months Ended September 30, 2018 Compared to Three Months Ended September 30, 2017

Gross Operating Margin. Gross operating margin was $417.7 million for the three months ended September 30, 2018 compared to $344.7 million for the three months ended September 30, 2017 , an increase of $73.0 million , or 21.2% , due to the following:

- *Texas Segment.* Gross operating margin in the Texas segment increased $14.9 million , which was due to a $10.9 million increase from our Permian Basin processing assets as a result of higher volumes from continued development by our customers and a $4.0 million increase associated with our Bridgeport gathering and processing volumes due to rate increases and volumes from new Devon wells not included under Devon's MVC. Gross operating margin for the remainder of our North Texas assets was flat quarter over quarter despite volume declines because the corresponding revenue decline was offset by an increase in revenue earned from MVCs (as discussed in more detail below). For the three months ended September 30, 2018, the shortfall revenue from Devon-related MVCs was $22.1 million compared to $15.9 million for the three months ended September 30, 2017.

- *Louisiana Segment.* Gross operating margin in the Louisiana segment increased $11.1 million , which was due to an increase from our NGL transmission and fractionation assets as a result of higher volumes received from our Permian Basin and Oklahoma assets.

- *Oklahoma Segment.* Gross operating margin in the Oklahoma segment increased $33.3 million , which was primarily due to higher volumes from continued development by our customers. For the three months ended September 30, 2018, there was no shortfall revenue from Devon-related MVCs compared to $4.0 million for the three months ended September 30, 2017.

- *Crude and Condensate Segment.* Gross operating margin in the Crude and Condensate segment increased $13.6 million , which was partially due to a $5.8 million increase from our ORV assets due to higher condensate stabilization volumes and improved margins from contract renegotiations. In addition, there was a $5.8 million increase from our Midland Basin crude business as a result of increased trucked volumes, higher trucking fees, and higher volumes due to continued expansion of our customer base on the Greater Chickadee gathering system.

- *Corporate Segment.* Gross operating margin in the Corporate segment increased $0.1 million , which was due to the changes in fair value of our commodity swaps between the periods. For the three months ended September 30, 2018 , there were realized losses of $4.6 million in addition to unrealized losses of $0.8 million . For the three months ended September 30, 2017 , there were realized losses of $2.2 million in addition to unrealized losses of $3.3 million .

Certain gathering and processing agreements in our Texas, Oklahoma, and Crude and Condensate segments provide for quarterly or annual MVCs, including MVCs from Devon from certain of our Barnett Shale assets in North Texas and our Cana gathering and processing assets in Oklahoma. 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):

	Texas		Oklahoma		Crude and Condensate		Total	
Three Months Ended								
September 30, 2018								
Midstream services	$	17.7	$	—	$	2.1	$	19.8
Midstream services—related parties		4.4		—		0.6		5.0
Total	$	22.1	$	—	$	2.7	$	24.8
September 30, 2017								
Midstream services	$	—	$	4.9	$	—	$	4.9
Midstream services—related parties		15.9		4.0		3.1		23.0
Total	$	15.9	$	8.9	$	3.1	$	27.9

On January 1, 2019, certain MVCs related to gathering and processing agreements with Devon for operations in the Texas and Oklahoma segments will expire. These MVCs generated $22.1 million and $19.6 million in shortfall revenue for the three months ended September 30, 2018 and 2017 , respectively. Additionally, on July 31, 2019, an MVC related to a transportation services agreement with Devon for operations in the Crude and Condensate segment will expire. This MVC generated $2.7 million and $3.1 million in shortfall revenue for the three months ended September 30, 2018 and 2017 , respectively.

Operating Expenses . Operating expenses were $114.7 million for the three months ended September 30, 2018 compared to $102.1 million for the three months ended September 30, 2017 , an increase of $12.6 million , or 12.3% . The primary contributors to the total increase by segment were as follows (in millions):

	Three Months Ended September 30,				Change		
	2018		2017		$		%
Texas Segment	$	44.7	$	41.1	$	3.6	8.8 %
Louisiana Segment		28.7		24.8		3.9	15.7 %
Oklahoma Segment		22.5		17.1		5.4	31.6 %
Crude and Condensate Segment		18.8		19.1		(0.3)	(1.6)%
Total	$	114.7	$	102.1	$	12.6	12.3 %

- *Texas Segment.* Operating expenses in the Texas segment increased $3.6 million primarily due to expanded operations and higher utilities expense in the Permian Basin.
- *Louisiana Segment.* Operating expenses in the Louisiana segment increased $3.9 million primarily due to increased utilities, operational fees and services, and materials and supplies expenses as a result of higher volumes across our Louisiana assets.
- *Oklahoma Segment.* Operating expenses in the Oklahoma segment increased $5.4 million primarily due to increased labor and benefits expenses due to increased headcount, as well as increases in materials and supplies, utilities, operational fees and services, treater rentals, and compression expenses as a result of expanded operations on our Oklahoma assets.
- *Crude and Condensate Segment.* Operating expenses in the Crude and Condensate segment decreased $0.3 million primarily due to decreases in third-party transportation charges.

General and Administrative Expenses . General and administrative expenses were $39.2 million for the three months ended September 30, 2018 compared to $30.0 million for the three months ended September 30, 2017 , an increase of $9.2 million , or 30.7% . The primary contributors to the increase were as follows:

- Unit-based compensation expense increased $4.5 million due to accelerated vestings related to the GIP Transaction and an organizational realignment in the third quarter of 2018.
- Salaries and wages expense increased $2.7 million due to severance expense related to an organizational realignment in the third quarter of 2018.
- Transaction costs increased $1.5 million due to costs we incurred related to the GIP Transaction.

Depreciation and Amortization . Depreciation and amortization expenses were $146.7 million for the three months ended September 30, 2018 compared to $136.3 million for the three months ended September 30, 2017 , an increase of $10.4 million , or 7.6% . This increase was primarily due to increased depreciation expense of $4.5 million and $1.5 million from completed projects in Central Oklahoma and the Permian Basin, respectively, and accelerated depreciation expense due to a change in the useful lives of certain underutilized assets in our Louisiana segment of $3.3 million.

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. We recognized impairment expense for the three months ended September 30, 2017 of $1.8 million related to the carrying values of rights-of-way that we are no longer using and a brine disposal well that was abandoned.

Interest Expense . Interest expense was $44.1 million for the three months ended September 30, 2018 compared to $48.9 million for the three months ended September 30, 2017 , a decrease of $4.8 million , or 9.8% . Interest expense consisted of the following (in millions):

	Three Months Ended September 30,	
	2018	**2017**
Senior notes	$ 40.0	$ 40.0
Credit facility	6.9	2.5
Capitalized interest	(2.3)	(1.1)
Amortization of debt issue costs and net discounts	0.8	7.3
Other	(1.3)	0.2
Total	$ 44.1	$ 48.9

Nine Months Ended September 30, 2018 Compared to Nine Months Ended September 30, 2017

Gross Operating Margin. Gross operating margin was $1,237.0 million for the nine months ended September 30, 2018 compared to $995.5 million for the nine months ended September 30, 2017 , an increase of $241.5 million , or 24.3% , due to the following:

- *Texas Segment.* Gross operating margin in the Texas segment increased $30.8 million , which was primarily due to a $29.9 million increase from our Permian Basin processing assets as a result of higher volumes due to continued development by our customers. Gross operating margin for our North Texas assets was relatively flat quarter over quarter despite volume declines because of increased revenue earned from MVCs (as discussed in more detail below). For the nine months ended September 30, 2018, the shortfall revenue from Devon-related MVCs was $61.1 million compared to $42.1 million for the nine months ended September 30, 2017.
- *Louisiana Segment.* Gross operating margin in the Louisiana segment increased $41.4 million , which was primarily due to a $38.4 million increase in our NGL transmission and fractionation gross operating margin due to additional NGL volumes received from our Oklahoma and Permian Basin assets and fees earned from the start-up of our Ascension JV assets in April 2017, as well as a $3.0 million increase from our Louisiana gas business as a result of higher volumes.

- *Oklahoma Segment.* Gross operating margin in the Oklahoma segment increased $170.9 million , which was primarily due to a $125.4 million increase from higher volumes as a result of continued development by our customers. In addition, during the nine months ended September 30, 2018, we restructured a contract with a customer, which resulted in the recognition of $45.5 million in revenue for the nine months ended September 30, 2018 (as discussed in "Item 1. Financial Statements — Note 2 "). For the nine months ended September 30, 2018, the shortfall revenue from Devon-related MVCs was $1.2 million compared to $12.0 million for the nine months ended September 30, 2017.

- *Crude and Condensate Segment.* Gross operating margin in the Crude and Condensate segment increased $17.4 million , which was partially due to a $7.3 million increase from our ORV assets due to higher condensate stabilization volumes and improved margins from contract renegotiations. In addition, there was an $8.6 million increase from our Midland Basin crude business as a result of increased trucking volumes, higher trucking fees, and higher volumes due to continued expansion of our customer base on the Greater Chickadee gathering system.

- *Corporate Segment.* Gross operating margin in the Corporate segment decreased $19.0 million due to the changes in fair value of our commodity swaps between the periods. For the nine months ended September 30, 2018 , there were realized losses of $5.3 million in addition to unrealized losses of $14.8 million . For the nine months ended September 30, 2017 , there were realized losses of $4.9 million were partially offset by unrealized gains of $3.8 million .

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

	Texas	Oklahoma	Crude and Condensate	Total
Nine Months Ended				
September 30, 2018				
Midstream services (1)	$ 17.8	$ 52.7	$ 2.1	$ 72.6
Midstream services—related parties	43.3	1.2	6.3	50.8
Total	$ 61.1	$ 53.9	$ 8.4	$ 123.4
September 30, 2017				
Midstream services	$ 0.8	$ 11.1	$ —	$ 11.9
Midstream services—related parties	42.1	12.0	5.9	60.0
Total	$ 42.9	$ 23.1	$ 5.9	$ 71.9

(1) We restructured a natural gas gathering and processing contract 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 . For more information, see "Item 1. Financial Statements— Note 2 ."

On January 1, 2019, certain MVCs related to gathering and processing agreements with Devon for operations in the Texas and Oklahoma segments will expire. These MVCs generated $62.3 million and $53.7 million in shortfall revenue for the nine months ended September 30, 2018 and 2017 , respectively. Additionally, on July 31, 2019, an MVC related to a transportation services agreement with Devon for operations in the Crude and Condensate segment will expire. This MVC generated $8.4 million and $5.9 million in shortfall revenue for the nine months ended September 30, 2018 and 2017 , respectively.

In May 2018, we restructured one of our natural gas gathering and processing contracts that included MVCs that were in effect through 2023. Prior to the contract restructuring, we expected $135.1 million in guaranteed future gross operating margin under the contract, generated from either revenue or reductions to cost of sales resulting from both gathering and processing fees as well as shortfall revenue under the MVCs. As a result of the contract restructuring, all MVC provisions were removed from the contract, and we and the counterparty entered into additional agreements pursuant to which: (i) the counterparty made a $19.7 million payment to us on the date of the contract restructuring to satisfy MVC revenue earned up to the date of the contract restructuring; (ii) the counterparty entered into a second lien secured term loan under which the counterparty will pay us $58.0 million in principal payments in various installments ending in May 2023, with interest accruing on the loan balance at 8.0% per annum beginning in 2020; and (iii) the counterparty granted to us a 1.0% term overriding royalty interest through June 2034 in each well located on leasehold interests of the counterparty and connected to the gas gathering system that we operate. As a result of the contract restructuring and in accordance with ASC 606, we recognized $45.5 million of midstream services revenue, which primarily represents the discounted present value of the second lien secured term loan receivable, in the Oklahoma segment in the second quarter of 2018. Pursuant to the contract restructuring, the terms of the restructured contract, other than the MVCs, are the same as the original contract, and we expect to continue recognizing gathering and processing fees on volumes delivered by the customer.

Operating Expenses. Operating expenses were $337.3 million for the nine months ended September 30, 2018 compared to $308.8 million for the nine months ended September 30, 2017 , an increase of $28.5 million , or 9.2% . The primary contributors to the increase by segment were as follows (in millions):

	Nine Months Ended September 30,		Change	
	2018	2017	$	%
Texas Segment	$ 134.7	$ 127.9	$ 6.8	5.3 %
Louisiana Segment	82.3	74.8	7.5	10.0 %
Oklahoma Segment	64.0	45.9	18.1	39.4 %
Crude and Condensate Segment	56.3	60.2	(3.9)	(6.5)%
Total	$ 337.3	$ 308.8	$ 28.5	9.2 %

- *Texas Segment.* Operating expenses in the Texas segment increased $6.8 million primarily due to expanded operations and higher utilities expense in the Permian Basin.

- *Louisiana Segment.* Operating expenses in the Louisiana segment increased $7.5 million primarily due to increased utilities, operational fees and services, labor and benefits charges, and materials and supplies expenses as a result of the start-up of the Ascension JV in April 2017 and higher volumes across our Louisiana assets.

- *Oklahoma Segment.* Operating expenses in the Oklahoma segment increased $18.1 million primarily due to increased labor and benefits expenses due to increased headcount, as well as an increase in materials and supplies, operational fees and services, treater rentals, ad valorem tax, and compression expenses as a result of expanded operations.

- *Crude and Condensate Segment.* Operating expenses in the Crude and Condensate segment decreased $3.9 million primarily due to decreases in third-party transportation charges.

Depreciation and Amortization. Depreciation and amortization expenses were $430.1 million for the nine months ended September 30, 2018 compared to $407.1 million for the nine months ended September 30, 2017 , an increase of $23.0 million , or 5.6% . This increase was primarily due to increased depreciation expense of $17.7 million and $3.7 million from completed projects in Central Oklahoma and the Permian Basin, respectively, and accelerated depreciation expense due to a change in the useful lives of certain underutilized assets in our Louisiana segment of $3.3 million.

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. We recognized impairment expense for the nine months ended September 30, 2017 of $8.8 million related to the carrying values of rights-of-way that we are no longer using and a brine disposal well that was abandoned.

Gain on Litigation Settlement. We settled a lawsuit in 2017 and recognized a gain on litigation settlement of $26.0 million for the nine months ended September 30, 2017 .

Gain on Extinguishment of Debt. We recognized a gain on extinguishment of debt of $9.0 million for the nine months ended September 30, 2017 due to the redemption of $162.5 million in aggregate principal amount of our 7.125% senior unsecured notes due 2022.

Interest Expense. Interest expense was $131.5 million for the nine months ended September 30, 2018 compared to $140.5 million for the nine months ended September 30, 2017 , a decrease of $9.0 million , or 6.4% . Interest expense consisted of the following (in millions):

	Nine Months Ended September 30,	
	2018	2017
Senior notes	$ 120.0	$ 115.0
Credit facility	15.2	8.4
Capitalized interest	(5.1)	(5.1)
Amortization of debt issue costs and net discounts (premium)	3.2	21.6
Other	(1.8)	0.6
Total	$ 131.5	$ 140.5

Income (Loss) from Unconsolidated Affiliate Investments. Income from unconsolidated affiliate investments was $11.7 million for the nine months ended September 30, 2018 compared to $5.0 million for the nine months ended September 30, 2017 , an increase of $6.7 million . The increase was primarily due to additional income of $5.5 million from our GCF investment as a result of higher fractionation revenues and lower operating expenses and a $3.4 million loss on the sale of our HEP investment for the nine months ended September 30, 2017 . These increases were offset by a $2.2 million decrease in income from our Cedar Cove JV for the nine months ended September 30, 2018 .

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, 2017 , except for our critical accounting policy on revenue recognition, which changed as a result of the adoption of ASC 606 on January 1, 2018. See “Item 1. Financial Statements— Note 2 ” for information on our revenue recognition accounting policy.

Liquidity and Capital Resources

Cash Flows from Operating Activities . Net cash provided by operating activities was $543.8 million for the nine months ended September 30, 2018 compared to $533.0 million for the nine months ended September 30, 2017 . Operating cash flows and changes in working capital for comparative periods were as follows (in millions):

	Nine Months Ended September 30,	
	2018	2017
Operating cash flows before working capital	$ 689.8	$ 537.3
Changes in working capital	(146.0)	(4.3)

Operating cash flows before changes in working capital increased $152.5 million for the nine months ended September 30, 2018 compared to the nine months ended September 30, 2017 primarily due to a $214.3 million increase in gross operating margin, excluding gains and losses on derivative activity and excluding non-cash revenue recognized from the restructuring of a contract (as discussed in “Item 1. Financial Statements— Note 2 ”) . The increase in operating cash flows was partially offset by a $9.4 million increase in interest expense, excluding amortization of debt issue costs and net discounts, as well as a $26.0 million gain on litigation settlement recognized for the nine months ended September 30, 2017. The remaining difference is due to higher cash paid for operating expenses and general and administrative expenses for the nine months ended September 30, 2018. The changes in working capital for the nine months ended September 30, 2018 compared to the nine months ended September 30, 2017 were primarily due to fluctuations in trade receivable and payable balances due to timing of collection and payments and changes in inventory balances attributable to normal operating fluctuations.

Cash Flows from Investing Activities . Net cash used in investing activities was $633.0 million for the nine months ended September 30, 2018 , compared to $475.3 million for the nine months ended September 30, 2017 . Our primary investing cash flows were as follows (in millions):

	Nine Months Ended September 30,	
	2018	2017
Growth capital expenditures	$ (608.8)	$ (641.1)
Maintenance capital expenditures	(30.6)	(21.4)
Proceeds from sale of unconsolidated affiliate investment	—	189.7

Growth capital expenditures decreased $32.3 million for the nine months ended September 30, 2018 compared to the nine months ended September 30, 2017 . The decrease was primarily due to completion of capital expenditures in 2017 related to the Greater Chickadee crude oil gathering system in the Permian Basin and the Ascension JV assets in Louisiana, in addition to lower capital expenditure levels for our expansion projects in the Central Oklahoma assets compared to 2017. Increased capital expenditures related to our Avenger crude gathering system and the Lobo III gas processing plant in the Delaware Basin during 2018 partially offset the decreases in the Permian Basin, Louisiana, and Central Oklahoma.

We completed the sale of our ownership interest in HEP in March 2017 and received net proceeds of $189.7 million.

Cash Flows from Financing Activities . Net cash provided by financing activi ties was $122.0 million for the nine months ended September 30, 2018 and $72.4 million for the nine months ended September 30, 2017 . Our primary financing activities consisted of the following (in millions):

	Nine Months Ended September 30,	
	2018	2017
Net borrowing (repayment) on credit facility	$ 765.0	$ (120.0)
Unsecured senior notes borrowings, net of notes extinguished	—	331.6
Proceeds from issuance of common units	46.1	92.3
Proceeds from issuance of Series C Preferred Units	—	393.7
Contributions by non-controlling interests	122.0	105.5
Payment of installment payable for EOGP acquisition	(250.0)	(250.0)

On May 11, 2017, we issued $500.0 million in aggregate principal amount of our 5.450% senior unsecured notes due June 1, 2047 at a price to the public of 99.981% of their face value. The net proceeds of approximately $495.2 million were used to repay outstanding borrowings under our credit facility and for general partnership purposes. For the nine months ended September 30, 2017, we redeemed $162.5 million in aggregate principal amount of our 7.125% senior unsecured notes due June 1, 2022 at 103.6% of the principal amount, plus accrued unpaid interest, for aggregate cash consideration of $174.1 million, which included payments for accrued interest of $5.8 million.

For the nine months ended September 30, 2018 , we sold an aggregate of approximately 2.6 million common units under the 2017 EDA, generating proceeds of approximately $46.1 million . For the nine months ended September 30, 2017 , we sold an aggregate of approximately 5.3 million common units under an equity distribution agreement entered into prior to the 2017 EDA, generating proceeds of $92.3 million .

In September 2017, we issued 400,000 Series C Preferred Units for net proceeds of $393.7 million .

For the nine months ended September 30, 2018 , contributions by non-controlling interests included $48.6 million from ENLC to EOGP and $73.6 million from NGP to the Delaware Basin JV. For the nine months ended September 30, 2017 , contributions by non-controlling interests included $59.3 million from ENLC to EOGP, $43.9 million from NGP to the Delaware Basin JV, and $2.3 million from Marathon Petroleum Corporation to the Ascension JV.

For the nine months ended September 30, 2018 and 2017 , we made the final two $250.0 million payments under the installment payable obligation related to the EOGP acquisition.

Distributions to unitholders, our general partner, and non-controlling interests also represent a primary use of cash in financing activities. Total cash distributions made for the nine months ended September 30, 2018 and 2017 were as follows (in millions):

	Nine Months Ended September 30,	
	2018	2017
Common units	$ 413.0	$ 406.4
General partner interest (including incentive distribution rights)	46.3	45.9
Distributions to non-controlling interests	37.6	17.0
Distributions to Series B Preferred Units	48.5	—
Distributions to Series C Preferred Units	12.0	—

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

Beginning with the quarter ended September 30, 2017, Series B Preferred Unit distributions were payable quarterly in cash in an amount per quarter 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 distributions that would have been payable had the Series B Preferred Units converted into common units for that quarter over the Cash Distribution Component, divided by (ii) the issue price of $15.00. The Series B Preferred Unit distributions paid in-kind in the form of additional Series B Preferred Units are non-cash distributions, and they are not reflected in our financing cash flows for the nine months ended September 30, 2018 and 2017.

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 15 th day of June and December of each year through and including December 15, 2022 and, thereafter, quarterly in arrears on the 15 th 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 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% .

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 2018 capital expenditures, including capital contributions to our unconsolidated affiliate investments, to be as follows (in millions):

		Remainder of 2018
Growth Capital Expenditures		
Texas segment	$	38 - 58
Louisiana segment		10 - 30
Oklahoma segment (1)		105 - 145
Crude and Condensate segment		33 - 68
Corporate segment		2 - 2
Total growth capital expenditures	$	188 - 303
Less: Growth capital expenditures funded by joint venture partners (2)		(9 - 43)
Growth capital expenditures, attributable to ENLK	$	179 - 260
Maintenance Capital Expenditures	$	14 - 19

(1) Includes projected growth capital contributions related to our non-controlling interest share of the Cedar Cove JV.
(2) Includes growth capital expenditures that will be contributed by other entities and relate to the non-controlling interest share of our consolidated entities. These contributions include contributions by ENLC to EOGP, contributions by NGP to the Delaware Basin JV, and contributions by Marathon Petroleum Corporation to the Ascension JV.

Our primary capital projects for the remainder of 2018 and for 2019 include the construction of the Thunderbird gas processing plant and the Redbud crude oil gathering system in Central Oklahoma and the Avenger crude oil gathering system and the Lobo III processing plant in the Delaware Basin. See “Recent Developments” for further details.

We expect to fund growth capital expenditures from the proceeds of borrowings under our 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 2018 , 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, 2018 .

Total Contractual Cash Obligations. A summary of contractual cash obligations as of September 30, 2018 is as follows (in millions):

	Payments Due by Period						
	Total	Remainder 2018	2019	2020	2021	2022	Thereafter
Long-term debt obligations (1)	$ 3,500.0	$ —	$ 400.0	$ —	$ —	$ —	$ 3,100.0
Credit facility	765.0	—	—	765.0	—	—	—
Interest payable on fixed long-term debt obligations	2,481.3	67.8	154.5	149.2	149.2	149.2	1,811.4
Capital lease obligations	3.1	0.4	1.5	1.2	—	—	—
Operating lease obligations	102.9	3.9	13.3	9.8	8.7	8.6	58.6
Purchase obligations	41.3	16.8	24.5	—	—	—	—
Delivery contract obligation	13.5	4.5	9.0	—	—	—	—
Pipeline capacity and deficiency agreements (2)	180.6	5.7	26.2	27.2	27.2	26.8	67.5
Inactive easement commitment (3)	10.0	—	—	—	—	10.0	—
Total contractual obligations	$ 7,097.7	$ 99.1	$ 629.0	$ 952.4	$ 185.1	$ 194.6	$ 5,037.5

(1) $400.0 million in aggregate principal amount of our 2.7% senior unsecured notes mature on April 1, 2019.
(2) Consists of pipeline capacity payments for firm transportation and deficiency agreements.
(3) 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 our credit facility is not reflected in the above table because such amounts depend on the outstanding balances and interest rates, which vary from time to time.

Our contractual cash obligations for the next twelve months are expected to be funded from cash flows generated from our operations, proceeds from our common unit issuances under the 2017 EDA, asset sales, and borrowings under our credit facility.

Indebtedness

We have a $1.5 billion unsecured revolving credit facility that matures on March 6, 2020 and includes a $500.0 million letter of credit subfacility. As of September 30, 2018 , there were $9.3 million in outstanding letters of credit and $765.0 million outstanding borrowings under our credit facility, leaving approximately $725.7 million available for future borrowing.

In addition, as of September 30, 2018 , we have $3.5 billion in aggregate principal amount of outstanding unsecured senior notes with $400.0 million maturing in April 2019 and the remaining amount maturing from 2024 to 2047.

See “Item 1. Financial Statements— Note 5 ” 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, Part II, "Item 1A. Risk Factors" of our Quarterly Report on Form 10-Q for the quarter ended June 30, 2018, and in Part I, "Item 1A . Risk Factors" of our Annual Report on Form 10-K for the year ended December 31, 2017 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 new relevant regulations that mandate that certain derivatives products be subject to margin requirements, cleared at a clearinghouse, or executed on an exchange. 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 new 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 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 has withdrawn its appeal of the court order vacating the original position limits rule. However, in November 2013, the CFTC proposed new rules that would place limits on positions in certain core futures and equivalent swaps contracts for or linked to certain physical commodities, subject to exceptions for certain bona fide hedging transactions. In December 2016, the CFTC modified and reproposed its positions limits rules. The CFTC has sought comment on the position limits rule as reproposed, but these new position limit rules are not yet final and the impact of those 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 new legislation and any future 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, 2018 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, 2018 , less than 2% of our contracts, based on gross operating margin, were under 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, 2018 , approximately 9% of our contracts, based on gross operating margin, were under 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, 2018 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 2018 - June 2019	Ethane	559 (MBbls)	$0.5198/gal	Index	$ 2.2
October 2018 - September 2019	Propane	776 (MBbls)	Index	$1.0464/gal	(7.0)
October 2018 - September 2019	Normal Butane	343 (MBbls)	Index	$1.2588/gal	(2.9)
October 2018 - September 2019	Natural Gasoline	162 (MBbls)	Index	$1.6408/gal	(1.2)
October 2018 - October 2019	Natural Gas	54,468 (MMBtu/d)	Index	$2.2107/MMBtu	(1.0)
October 2018 - December 2022	Crude and condensate	14,618 (MBbls)	Index	$68.69/bbl	(6.5)
					$ (16.4)

(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, 2018 , outstanding natural gas swap agreements, NGL swap agreements, swing swap agreements, storage swap agreements, and other derivative instruments were a net fair value liability of $16.4 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 $10.4 million in the net fair value of these contracts as of September 30, 2018 .

Interest Rate Risk

We are exposed to interest rate risk on our variable rate credit facility. At September 30, 2018 , we had $765.0 million in outstanding borrowings under this facility. A 1% increase or decrease in interest rates would change our annualized interest expense by approximately $7.7 million for the year.

We are not exposed to changes in interest rates with respect to our senior unsecured notes due in 2019, 2024, 2025, 2026, 2044, 2045 or 2047 as these are fixed-rate obligations. The estimated fair value of our senior unsecured notes was approximately $3,252.6 million as of September 30, 2018 , based on market prices of similar debt at September 30, 2018 . Market risk is estimated as the potential decrease in fair value of our long-term debt resulting from a hypothetical increase of 1% in interest rates. Such an increase in interest rates would result in an approximate $230.6 million decrease in fair value of our senior unsecured notes at September 30, 2018 .

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, 2018), 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, 2018, we adopted ASC 606 . The adoption of this accounting standard had no impact on our operating income, results of operations, financial condition, or cash flows. While the adoption of ASC 606 did not materially affect our internal control over financial reporting, we did implement certain changes to our related revenue recognition control activities, including changes to our policies related to the revenue recognition model, training, ongoing 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, 2018 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

Except as set forth below, 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, 2017 and in Part II, "Item 1A. Risk Factors" of our Quarterly Report on Form 10-Q for the quarter ended June 30, 2018.

Risks Related to the Merger Transactions

The Merger Transactions are subject to conditions and may not be consummated even if the required unitholder approvals are obtained, which may cause the market price of the ENLK common units to decline.

The Merger Transactions are subject to the satisfaction or waiver of certain conditions, including the approval of the Merger Agreement by the holders of a majority of the common units and the Series B Preferred Units, voting together as a single class (the "ENLK Voting Unitholders"). The Merger Agreement contains other conditions that, if not satisfied or waived, would result in the Merger Transactions not occurring, even though the ENLK Voting Unitholders may have approved the Merger Agreement. Satisfaction of some of these other conditions to the Merger Transactions is not entirely in the control of ENLK and ENLC. The closing conditions to the Merger Transactions may not be satisfied, and ENLK and ENLC may choose not to, or may be unable to, waive an unsatisfied condition, which may cause the Merger Transactions not to occur.

The Merger Agreement contains certain termination rights for both ENLK and ENLC, including, among others, (i) by the mutual written agreement of ENLK (duly authorized by the conflicts committee of the Board of Directors of ENLK's general partner (the "ENLK Conflicts Committee")) and ENLC (duly authorized by the Board of Directors of the managing member of ENLC); (ii) by either ENLK or ENLC, if (A) the Merger has not been consummated on or before June 30, 2019; or (B) the requisite approval of the ENLK Voting Unitholders of the Merger Agreement is not obtained; (iii) by ENLC, if (A) the Board of Directors of ENLK's general partner (upon the recommendation of the ENLK Conflicts Committee) or the ENLK Conflicts Committee makes a Recommendation Change (as defined in the Merger Agreement) prior to the meeting of the ENLK Voting Unitholders to consider and vote on the approval of the Merger Agreement or (B) if under certain conditions, there has been a material breach by ENLK of any of its representations, warranties, or covenants set forth in the Merger Agreement that is not cured within 30 days of notice of such breach; and (iv) by ENLK, if (A) subject to certain conditions, ENLK has received a Superior Proposal (as defined in the Merger Agreement) and the Board of Directors of ENLK's general partner (upon the recommendation of the ENLK Conflicts Committee) or the ENLK Conflicts Committee has determined in good faith that the failure to terminate the Merger Agreement would be inconsistent with its fiduciary duties, or (B) under certain conditions, there has been a material breach by ENLC of any of its representations, warranties, or covenants set forth in the Merger Agreement that is not cured within 30 days of notice of such breach. The Merger Agreement further provides that, upon termination of the Merger Agreement under certain circumstances, ENLK or ENLC, as applicable, may be required to reimburse the other party's expenses up to $5 million, and, in certain circumstances, ENLK may be required to pay ENLC a termination fee equal to $55 million.

If the Merger Transactions do not occur for any reason or if there are significant delays in completing the Merger Transactions, ENLK's business and financial results could be negatively affected and the market price of ENLK common units may decline.

ENLK and ENLC may incur substantial transaction-related costs in connection with the Merger Transactions.

ENLK and ENLC expect to incur nonrecurring transaction-related costs associated with completing the Merger Transactions. Nonrecurring transaction costs include, but are not limited to, fees paid to legal, financial, and accounting advisors, registration and regulatory filing fees, proxy solicitation costs, and printing costs.

Failure to complete, or significant delays in completing, the Merger Transactions could negatively affect the trading price of ENLK's common units and our future business and financial results.

Completion of the Merger Transactions is not assured and is subject to risks, including the risks that approval of the Merger Transactions by the ENLK Voting Unitholders or by any applicable governmental agencies or third parties is not obtained or that other closing conditions are not satisfied. If the Merger Transactions are not completed, or if there are significant delays in completing the Merger Transactions, the trading price of ENLK's common units and our future business and financial results could be negatively affected, and we will be subject to several risks, including the following:

- ENLK and ENLC may be liable for damages to one another under the terms and conditions of the Merger Agreement;
- negative reactions from the financial markets, including declines in the price of ENLK's common units due to the fact that the current price may reflect a market assumption that the Merger Transactions will be completed;
- having to pay certain significant costs relating to the Merger Transactions; and
- the attention of management may have been diverted to the Merger Transactions rather than our own operations and pursuit of other opportunities that could have been beneficial to us.

We may not realize the benefits we expect from the Merger Transactions.

We believe that the Merger Transactions will, among other things, provide increased financial flexibility for execution of our strategic growth plan. However, our assessments and expectations regarding the anticipated benefits of the Merger Transactions may prove to be incorrect. Accordingly, there can be no assurance we will realize the anticipated benefits of the Merger Transactions.

We are subject to provisions that limit our ability to pursue alternatives to the Merger Transactions and could discourage a potential acquirer of ours that does not want the Merger Transactions completed from making a favorable alternative transaction proposal.

Unless and until the Merger Agreement is terminated, subject to specified exceptions, we are restricted from, among other things, initiating, soliciting, knowingly encouraging or knowingly facilitating, any inquiry, proposal, or offer for certain acquisition proposals for ENLK. These and other provisions in the Merger Agreement could discourage a third party that may have an interest in acquiring all or a significant part of ENLK from considering or proposing that acquisition.

The Merger Transactions should be a taxable transaction and, in such case, the resulting tax liability of an ENLK common unitholder, if any, will depend on the unitholder's particular situation. The tax liability of an ENLK common unitholder as a result of the Merger Transactions could be more than expected.

ENLK common unitholders (other than ENLC and its subsidiaries) will receive solely ENLC common units as consideration in the Merger. Although ENLK common unitholders will receive no cash consideration, the Merger will be treated as a taxable sale of ENLK common units for U.S. federal income tax purposes. As a result, our holders will generally recognize (i) ordinary income to the extent of the holder's share of "unrealized receivables," including depreciation recapture, and "inventory items" owned by ENLK and its subsidiaries and (ii) capital gain or capital loss equal to the difference between the holder's amount realized and the sum of the holder's tax basis in its ENLK common units and the amount of ordinary income recognized by the holder as described in clause (i). The amount of ordinary income and capital gain or loss recognized by each ENLK common unitholder in the Merger will vary depending on each unitholder's particular situation, including the value of the ENLC common units received by each unitholder in the Merger, the amount of depreciation and amortization deductions previously passed-through from ENLK to the unitholder, the adjusted tax basis of the ENLK common units exchanged by each unitholder in the Merger, and the amount of any suspended passive losses that may be available to a particular unitholder to offset a portion of the gain recognized by the unitholder.

Because the fair market value of any ENLC common unit received in the Merger will not be known until the effective time of the Merger, an ENLK common unitholder will not be able to determine its amount realized, and therefore its taxable gain or loss, until such time. In addition, because prior distributions in excess of an ENLK common unitholder's allocable share of ENLK's net taxable income decrease the unitholder's tax basis in its ENLK common units, the amount, if any, of the prior excess distributions with respect to such common units will, in effect, become taxable income to a unitholder if the aggregate value of the consideration received in the Merger is greater than the unitholder's adjusted tax basis in its ENLK common units, even if the aggregate value of the consideration received in the Merger is less than the unitholder's original cost basis in its ENLK common units. Furthermore, a portion of this gain or loss, which could be substantial, will be separately computed and taxed as ordinary income or loss to the extent attributable to "unrealized receivables," including depreciation recapture, or to "inventory items" owned by ENLK and its subsidiaries.

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

During the three months ended September 30, 2018 , we re-acquired ENLK common units from certain employees in order to satisfy the employees' tax liability in connection with the vesting of restricted incentive units.

Period	Total Number of Units Purchased (1)	Average Price Paid Per Unit	Total Number of Units Purchased as Part of Publicly Announced Plans or Programs	Maximum Number of Units that May Yet Be Purchased under the Plans or Programs
July 1, 2018 to July 31, 2018	79,700	$ 14.95	—	—
August 1, 2018 to August 31, 2018	61,808	17.15	—	—
September 1, 2018 to September 30, 2018	2,593	18.67	—	—
Total	144,101	$ 15.96	—	—

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

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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	—	Ninth Amended and Restated Agreement of Limited Partnership of EnLink Midstream Partners, LP, dated as of September 21, 2017 (incorporated by reference to Exhibit 3.1 to our Current Report on Form 8-K dated September 21, 2017, filed with the Commission on September 21, 2017, file No. 001-36340).
3.6	—	Amendment No. 1 to Ninth Amended and Restated Agreement of Limited Partnership of EnLink Midstream Partners, LP, dated as of December 12, 2017 (incorporated by reference to Exhibit 3.1 to our Current Report on Form 8-K dated December 12, 2017, filed with the Commission on December 14, 2017, file No. 001-36340).
3.7	—	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).
3.8	—	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).
3.9	—	Fourth Amended and Restated Limited Liability Company Agreement of EnLink Midstream GP, LLC, dated as of July 18, 2018 (incorporated by reference to Exhibit 3.1 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	—	Second Amendment to Credit Agreement and Limited Consent, dated effective as of June 20, 2018, by and among EnLink Midstream Partners, LP, Bank of America, N.A., as Administrative Agent, and the lenders party thereto (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K dated June 20, 2018, filed with the Commission on June 25, 2018, file No. 001-36340).
10.2	—	Form of Indemnification Agreement (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K dated July 17, 2018, filed with the Commission on July 23, 2018, file No. 001-36340).
10.3	—	Support Agreement, dated as of October 21, 2018, by and among GIP III Stetson I, L.P., EnLink Midstream, LLC, Acacia Natural Gas Corp I., Inc., EnLink Midstream, Inc., and EnLink Midstream Partners, LP (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K dated October 21, 2018, filed with the Commission on October 22, 2018, file No. 001-36340).
10.4	—	Support Agreement, dated as of October 21, 2018, by and among Enfield Holdings, L.P., TPG VII Management, LLC, WSEP Egypt Holdings, LP, WSIP Egypt Holdings, LP, and EnLink Midstream Partners, LP (incorporated by reference to Exhibit 10.2 to our Current Report on Form 8-K dated October 21, 2018, filed with the Commission on October 22, 2018, file No. 001-36340).
10.5	—	Parent Support Agreement, dated as of October 21, 2018, by and among GIP III Stetson II, L.P. and EnLink Midstream Partners, LP (incorporated by reference to Exhibit 10.3 to our Current Report on Form 8-K dated October 21, 2018, filed with the Commission on October 22, 2018, file No. 001-36340).
10.6	—	Preferred Restructuring Agreement, dated as of October 21, 2018, by and among Enfield Holdings, L.P., TPG VII Management, LLC, WSEP Egypt Holdings, LP, WSIP Egypt Holdings, LP, EnLink Midstream, LLC, EnLink Midstream Manager, LLC, EnLink Midstream Partners, LP, and EnLink Midstream GP, LLC (incorporated by reference to Exhibit 10.4 to our Current Report on Form 8-K dated October 21, 2018, filed with the Commission on October 22, 2018, 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, 2018, formatted in XBRL (eXtensible Business Reporting Language): (i) Consolidated Balance Sheets as of September 30, 2018 and December 31, 2017, (ii) Consolidated Statements of Operations for the three and nine months ended September 30, 2018 and 2017, (iii) Consolidated Statements of Changes in Partners' Equity for the nine months ended September 30, 2018, (iv) Consolidated Statements of Cash Flows for the nine months ended September 30, 2018 and 2017, and (v) the Notes to Consolidated Financial Statements.

* Filed herewith.

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 7, 2018

Exhibit 31.1

CERTIFICATIONS

I, Michael J. Garberding, 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 7, 2018

/s/ MICHAEL J. GARBERDING

Michael J. Garberding

President and 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 7, 2018

/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, 2018 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), each of the undersigned, Michael J. Garberding, 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 7, 2018

/s/ MICHAEL J. GARBERDING
Michael J. Garberding
Chief Executive Officer

Date: November 7, 2018

/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.