Table of Contents

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, 2017

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 and posted on its corporate website, if any, every Interactive Data File required to be submitted and posted 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	☐
(Do not check if a 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 October 26, 2017, the Registrant had 349,008,666 common units outstanding.

TABLE OF CONTENTS

DEFINITIONS

The following terms as defined are used in the energy industry and in this document:

/d = per day
Bbls = barrels
Bcf = billion cubic feet
Gal = gallon
Mcf = thousand cubic feet
MMBtu = million British thermal units
MMcf = million cubic feet
NGL = natural gas liquid and natural gas liquids

PART I—FINANCIAL INFORMATION

Item 1. Financial Statements

ENLINK MIDSTREAM PARTNERS, LP
Consolidated Balance Sheets
(In millions, except unit data)

	September 30, 2017 (Unaudited)	December 31, 2016
ASSETS		
Current assets:		
Cash and cash equivalents	$ 141.7	$ 11.6
Accounts receivable:		
Trade, net of allowance for bad debt of $0.1 and $0.1, respectively	42.5	63.9
Accrued revenue and other	432.4	369.6
Related party	121.6	100.2
Fair value of derivative assets	4.6	1.3
Natural gas and NGLs inventory, prepaid expenses and other	73.0	31.0
Investment in unconsolidated affiliates—current	—	193.1
Total current assets	815.8	770.7
Property and equipment, net of accumulated depreciation of $2,428.5 and $2,124.1, respectively	6,568.8	6,256.7
Fair value of derivative assets	0.1	—
Intangible assets, net of accumulated amortization of $267.8 and $171.6, respectively	1,528.0	1,624.2
Goodwill	422.3	422.3
Investment in unconsolidated affiliates—non-current	86.1	77.3
Other assets, net	5.0	2.2
Total assets	$ 9,426.1	$ 9,153.4
LIABILITIES AND PARTNERS' EQUITY		
Current liabilities:		
Accounts payable and drafts payable	$ 65.2	$ 69.2
Accounts payable to related party	36.8	10.4
Accrued gas, NGLs, condensate and crude oil purchases	376.6	333.3
Fair value of derivative liabilities	7.2	7.6
Installment payable, net of discount of $7.0 and $0.5, respectively	243.0	249.5
Other current liabilities	234.5	217.0
Total current liabilities	963.3	887.0
Long-term debt	3,466.8	3,268.0
Asset retirement obligations	14.0	13.5
Installment payable, net of discount of $26.3 at December 31, 2016	—	223.7
Other long-term liabilities	38.7	42.6
Deferred tax liability	72.7	73.0
Redeemable non-controlling interest	4.6	5.2
Partners' equity:		
Common unitholders (348,764,883 and 342,856,292 units issued and outstanding, respectively)	2,873.9	3,193.2
Series B preferred unitholders (56,645,600 and 53,182,651 units issued and outstanding, respectively)	857.6	794.0
Series C preferred unitholders (400,000 units issued and outstanding at September 30, 2017)	394.4	—
General partner interest (1,594,974 equivalent units outstanding)	207.6	209.1
Accumulated other comprehensive loss	(2.2)	—
Non-controlling interest	534.7	444.1
Total partners' equity	4,866.0	4,640.4
Commitments and contingencies (Note 13)		
Total liabilities and partners' equity	$ 9,426.1	$ 9,153.4

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,		Nine Months Ended September 30,	
	2017	2016	2017	2016
	(Unaudited)			
Revenues:				
Product sales	$ 1,056.7	$ 771.0	$ 2,973.9	$ 2,097.8
Product sales—related parties	35.3	43.1	107.3	99.3
Midstream services	136.4	125.7	395.7	348.5
Midstream services—related parties	175.0	165.3	507.6	488.5
Loss on derivative activity	(5.5)	(0.5)	(1.1)	(6.6)
Total revenues	1,397.9	1,104.6	3,983.4	3,027.5
Operating costs and expenses:				
Cost of sales (1)	1,053.2	788.2	2,987.9	2,106.8
Operating expenses	102.1	98.0	308.8	296.3
General and administrative	30.0	28.3	94.6	90.6
(Gain) loss on disposition of assets	1.1	(3.0)	0.8	(2.9)
Depreciation and amortization	136.3	126.2	407.1	373.0
Impairments	1.8	—	8.8	566.3
Gain on litigation settlement	—	—	(26.0)	—
Total operating costs and expenses	1,324.5	1,037.7	3,782.0	3,430.1
Operating income (loss)	73.4	66.9	201.4	(402.6)
Other income (expense):				
Interest expense, net of interest income	(48.9)	(48.0)	(140.5)	(137.9)
Gain on extinguishment of debt	—	—	9.0	—
Income (loss) from unconsolidated affiliates	4.4	1.1	5.0	(0.5)
Other income	0.3	0.1	0.5	0.1
Total other expense	(44.2)	(46.8)	(126.0)	(138.3)
Income (loss) before non-controlling interest and income taxes	29.2	20.1	75.4	(540.9)
Income tax provision	(0.5)	(2.6)	(0.7)	(1.3)
Net income (loss)	28.7	17.5	74.7	(542.2)
Net income (loss) attributable to non-controlling interest	3.2	(1.3)	1.5	(5.6)
Net income (loss) attributable to EnLink Midstream Partners, LP	$ 25.5	$ 18.8	$ 73.2	$ (536.6)
General partner interest in net income	$ 10.6	$ 10.8	$ 27.3	$ 28.8
Limited partners' interest in net loss attributable to EnLink Midstream Partners, LP	$ (8.6)	$ (11.4)	$ (18.4)	$ (602.1)
Class C partners' interest in net loss attributable to EnLink Midstream Partners, LP	$ —	$ —	$ —	$ (12.5)
Series B preferred interest in net income attributable to EnLink Midstream Partners, LP	$ 22.8	$ 19.4	$ 63.6	$ 49.2
Series C preferred interest in net income attributable to EnLink Midstream Partners, LP	$ 0.7	$ —	$ 0.7	$ —
Net loss attributable to EnLink Midstream Partners, LP per limited partners' unit:				
Basic common unit	$ (0.02)	$ (0.03)	$ (0.05)	$ (1.82)
Diluted common unit	$ (0.02)	$ (0.03)	$ (0.05)	$ (1.82)

(1) Includes related party cost of sales of $47.3 million and $33.7 million for the three months ended September 30, 2017 and 2016, respectively, and $126.9 million and $126.0 million for the nine months ended September 30, 2017 and 2016, respectively.

See accompanying notes to consolidated financial statements.

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

	Three Months Ended September 30, 2017	Three Months Ended September 30, 2016	Nine Months Ended September 30, 2017	Nine Months Ended September 30, 2016
	(Unaudited)			
Net income (loss)	$ 28.7	$ 17.5	$ 74.7	$ (542.2)
Loss on designated cash flow hedge	—	—	(2.2)	—
Comprehensive income (loss)	28.7	17.5	72.5	(542.2)
Comprehensive income (loss) attributable to non-controlling interest	3.2	(1.3)	1.5	(5.6)
Comprehensive income (loss) attributable to EnLink Midstream Partners, LP	$ 25.5	$ 18.8	$ 71.0	$ (536.6)

See accompanying notes to consolidated financial statements.

ENLINK MIDSTREAM PARTNERS, LP
Consolidated Statement of Changes in Partners' Equity
Nine Months Ended September 30, 2017
(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, 2016	$ 3,193.2	342.9	$ 794.0	53.2	$ —	$ —	$ 209.1	1.6	$ —	$ 444.1	$ 4,640.4	$ 5.2
Issuance of common units	92.3	5.3	—	—	—	—	—	—	—	—	92.3	—
Issuance of Series C Preferred Units	—	—	—	—	393.7	0.4	—	—	—	—	393.7	—
Conversion of restricted units for common units, net of units withheld for taxes	(5.2)	0.6	—	—	—	—	—	—	—	—	(5.2)	—
Unit-based compensation	17.1	—	—	—	—	—	17.1	—	—	—	34.2	—
Contribution from Devon	1.3	—	—	—	—	—	—	—	—	—	1.3	—
Distributions	(406.4)	—	—	3.4	—	—	(45.9)	—	—	—	(452.3)	—
Non-controlling interest contributions	—	—	—	—	—	—	—	—	—	105.5	105.5	—
Distributions to non-controlling interest	—	—	—	—	—	—	—	—	—	(16.4)	(16.4)	—
Distributions to redeemable non-controlling interest	—	—	—	—	—	—	—	—	—	—	—	(0.6)
Unrealized loss on derivatives	—	—	—	—	—	—	—	—	(2.2)	—	(2.2)	—
Net income (loss)	(18.4)	—	63.6	—	0.7	—	27.3	—	—	1.5	74.7	—
Balance, September 30, 2017	$ 2,873.9	348.8	$ 857.6	56.6	$ 394.4	0.4	$ 207.6	1.6	$ (2.2)	$ 534.7	$ 4,866.0	$ 4.6

See accompanying notes to consolidated financial statements.

Table of Contents

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

	Nine Months Ended September 30, 2017	Nine Months Ended September 30, 2016
	(Unaudited)	
Cash flows from operating activities:		
Net income (loss)	$ 74.7	$ (542.2)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Impairments	8.8	566.3
Depreciation and amortization	407.1	373.0
(Gain) loss on disposition of assets	0.8	(2.9)
Non-cash unit-based compensation	38.7	22.5
Loss on derivatives recognized in net income (loss)	1.1	6.6
Gain on extinguishment of debt	(9.0)	—
Cash settlements on derivatives	(5.9)	9.5
Amortization of debt issue costs	2.8	2.6
Amortization on net discount of notes and installment payable	18.8	36.9
Redeemable non-controlling interest expense	—	0.3
(Income) loss from unconsolidated affiliates	(5.0)	0.5
Other	4.4	0.8
Changes in assets and liabilities, net of assets acquired and liabilities assumed:		
Accounts receivable, accrued revenue and other	(56.9)	(17.6)
Natural gas and NGLs inventory, prepaid expenses and other	(48.6)	3.6
Accounts payable, accrued gas and crude oil purchases and other accrued liabilities	101.2	49.3
Net cash provided by operating activities	533.0	509.2
Cash flows from investing activities, net of assets acquired and liabilities assumed:		
Additions to property and equipment	(662.5)	(423.7)
Proceeds from insurance settlement	0.2	0.3
Acquisition of business, net of cash acquired	—	(769.3)
Proceeds from sale of unconsolidated affiliate investment	189.7	—
Proceeds from sale of property	1.8	4.7
Investment in unconsolidated affiliates	(11.8)	(45.0)
Distribution from unconsolidated affiliates in excess of earnings	7.3	51.6
Net cash used in investing activities	(475.3)	(1,181.4)
Cash flows from financing activities:		
Proceeds from borrowings	2,151.9	1,629.3
Payments on borrowings	(1,940.3)	(1,469.2)
Payment of installment payable for EnLink Oklahoma T.O. acquisition	(250.0)	—
Payments on capital lease obligations	(2.1)	(3.2)
Debt financing costs	(5.5)	(4.6)
Conversion of restricted units, net of units withheld for taxes	(5.2)	(1.2)
Proceeds from issuance of common units	92.3	110.6
Proceeds from exercise of Partnership unit options	0.1	—
Proceeds from issuance of Series B Preferred Units	—	724.1
Proceeds from issuance of Series C Preferred Units	393.7	—
Distributions to non-controlling interests	(17.0)	(5.6)
Contributions by non-controlling interests, including contributions from affiliates of $59.3 and $27.9, respectively	105.5	179.4
Distribution to partners	(452.3)	(430.7)
Mandatorily redeemable non-controlling interest	—	(4.0)
Contribution from Devon	1.3	1.4
Net cash provided by financing activities	72.4	726.3
Net increase in cash and cash equivalents	130.1	54.1
Cash and cash equivalents, beginning of period	11.6	5.9
Cash and cash equivalents, end of period	$ 141.7	$ 60.0
Cash paid for interest	$ 93.2	$ 70.4
Cash paid for income taxes	$ 3.6	$ 2.5

See accompanying notes to consolidated financial statements.

ENLINK MIDSTREAM PARTNERS, LP
Notes to Consolidated Financial Statements
September 30, 2017
(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 (as defined below) and EnLink Oklahoma Gas Processing, LP ("EnLink Oklahoma T.O."). EnLink Oklahoma T.O. is sometimes used to refer to EnLink Oklahoma Gas Processing, LP itself or EnLink Oklahoma Gas Processing, LP together with its consolidated subsidiaries.

(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, EnLink Midstream Operating, LP, a Delaware limited partnership (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 EnLink Midstream, LLC ("ENLC"). ENLC's units are traded on the New York Stock Exchange under the symbol "ENLC." Devon Energy Corporation ("Devon") owns ENLC's managing member and common units representing approximately 64% of the outstanding limited liability company interests in ENLC.

(b) Nature of Business

We primarily focus on providing midstream energy services, including gathering, transmission, processing, fractionation, storage, condensate stabilization, brine services and marketing to producers of natural gas, NGLs, crude oil and condensate.

We connect the wells of producers in our market areas to our gathering systems, which consist of networks of pipelines that collect natural gas from points 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, which is transported to the plants by our own gathering systems or by major interstate and intrastate 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, other markets 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 through our transmission lines that transport NGLs from east Texas and from our south Louisiana processing plants. 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 transport the NGLs to our fractionators. In addition, we have NGL storage capacity to provide storage for customers.

We also provide a variety of crude oil and condensate services, which include crude oil and condensate gathering and transmission via pipelines, barges, rail and trucks, condensate stabilization and brine disposal. We have crude oil and condensate terminal facilities that provide market access for crude oil and condensate producers.

(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 generally accepted accounting principles in the United States of America ("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) Adopted Accounting Standards

In March 2016, the Financial Accounting Standards Board (the "FASB") issued Accounting Standards Update ("ASU") 2016-09, *Compensation—Stock Compensation (Topic 718): Improvements to Employee Share-Based Payment Accounting* ("ASU 2016-09"), which simplifies several aspects related to the accounting for share-based payment transactions. Effective January 1, 2017, we adopted ASU 2016-09. We prospectively adopted the guidance that requires excess tax benefits and deficiencies be recognized on the income statement. The cash flow statement guidance requires the presentation of excess tax benefits and deficiencies as an operating activity and the presentation of cash paid by an employer when directly withholding shares for tax-withholding purposes as a financing activity, and this treatment is consistent with our historical accounting treatment. Finally, we elected to estimate the number of awards that are expected to vest, which is consistent with our historical accounting treatment. The adoption of the new guidance did not materially affect the consolidated statements of operations for the three and nine months ended September 30, 2017.

In January 2017, the FASB issued ASU 2017-04, *Intangibles—Goodwill and Other (Topic 350)—Simplifying the Test for Goodwill Impairment* ("ASU 2017-04"). ASU 2017-04 simplifies the accounting for goodwill impairments by eliminating the requirement to compare the implied fair value of goodwill with its carrying amount as part of step two of the goodwill impairment test referenced in Accounting Standards Codification ("ASC") 350, *Intangibles—Goodwill and Other* ("ASC 350"). As a result, an entity should perform its annual or interim goodwill impairment test by comparing the fair value of a reporting unit with its carrying amount. An impairment charge should be recognized for the amount by which the carrying amount exceeds the reporting unit's fair value. However, the impairment loss recognized should not exceed the total amount of goodwill allocated to that reporting unit. ASU 2017-04 is effective for annual reporting periods beginning after December 15, 2019, including any interim impairment tests within those annual periods, with early application permitted for interim or annual goodwill impairment tests performed on testing dates after January 1, 2017. In January 2017, we elected to early adopt ASU 2017-04, and the adoption had no impact on our consolidated financial statements. We will perform future goodwill impairment tests according to ASU 2017-04.

(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"). 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. ASU 2016-02 is effective for annual reporting periods beginning after December 15, 2018, including interim periods within those annual periods. Early adoption is permitted. Entities are required to adopt ASU 2016-02 using a modified retrospective transition. We are currently assessing the impact of adopting ASU 2016-02. This assessment includes the gathering and evaluation of our current lease contracts and the analysis of contracts that may contain lease components. While we cannot currently estimate the quantitative effect that ASU 2016-02 will have on our consolidated financial statements, the adoption of ASU 2016-02 will increase our asset and liability balances on the consolidated balance sheets 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 addition, there are industry-specific concerns with the implementation of ASU 2016-02, including the application of ASU 2016-02 to contracts involving easements/right-of-ways, which will require further evaluation before we are able to fully assess the impact on our consolidated financial statements.

In May 2014, the FASB issued ASU 2014-09, *Revenue from Contracts with Customers* ("ASU 2014-09"), which established ASC Topic 606, *Revenue from Contracts with Customers* ("ASC 606"). ASC 606 will replace existing revenue recognition requirements in GAAP and will require 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 will also require 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. In May 2016, the FASB issued ASU 2016-12, *Revenue from Contracts with Customers (Topic 606): Narrow-Scope Improvements and Practical Expedients* ("ASU 2016-12"), which updated ASU 2014-09. ASU 2016-12 clarifies certain core recognition principles, including collectability, sales tax presentation, noncash consideration, contract modifications and completed contracts at transition and disclosures no longer required if the full retrospective transition method is adopted. ASU 2014-09 and ASU 2016-12 are effective for annual reporting periods beginning after December 15, 2017, including interim periods within those annual periods, and are to be applied using the modified retrospective or full retrospective transition methods, with early application permitted for annual reporting periods beginning after December 15, 2016. We will adopt ASC 606 using the modified retrospective method for annual and interim reporting periods beginning January 1, 2018.

We have aggregated and reviewed our contracts that are within the scope of ASC 606. Based on our evaluation to date, we do not anticipate the adoption of ASC 606 will have a material impact on our results of operations, financial condition or cash flows. However, ASC 606 will affect how certain transactions are recorded in the financial statements. For each contract with a customer, we will need to identify our performance obligations, of which the identification includes careful evaluation of when control and the economic benefits of the commodities transfer from our customer to us. The evaluation of control will change the way we account for certain transactions, specifically those in which there is both a commodity purchase component and a service component. 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 will not consider these revenue-generating contracts. Based on that determination, all fees or fee-equivalent deductions stated in such contracts would reduce the cost to purchase commodities. Alternatively, for contracts where control of commodities transfers to us after we perform our services, we have performance obligations for our services. Accordingly, we will consider the satisfaction of these performance obligations as revenue-generating and recognize these fees as midstream service revenues at the time 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 will recognize these fees as midstream services revenues at the time we satisfy our performance obligations. Based on our review of our performance obligations in our contracts with customers, we will change the statement of operations classification for certain transactions from revenue to cost of sales or from cost of sales to revenue. This reclassification of revenues and costs will have no effect on operating income.

Our performance obligations represent promises to transfer a series of distinct goods or services that are satisfied over time and that are substantially the same to the customer. As permitted by ASC 606, we will utilize the practical expedient that allows an entity to recognize revenue in the amount to which the entity has a right to invoice if an entity has a right to consideration from a customer in an amount that corresponds directly with the value to the customer of the entity's performance completed to date. Accordingly, ASC 606 will not significantly affect the timing of income and expense on the statement of operations, and we will continue to recognize revenue at the time commodities are delivered or services are performed.

Based on the disclosure requirements of ASC 606, upon adoption, we expect to provide expanded disclosures relating to our revenue recognition policies and how these relate to our revenue-generating contractual performance obligations. In addition, we expect to present revenues disaggregated based on the type of good or service in order to more fully depict the nature of our revenues.

(d) Property & Equipment

Impairment Review. We evaluate our property and equipment 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 nine months ended September 30, 2017, we recognized impairments of $8.8 million, which related to the carrying values of rights-of-way that we are no longer using and an abandoned brine disposal well.

(e) Comprehensive Income (Loss)

Comprehensive income (loss) is composed of net income (loss) and other comprehensive income (loss), which consists of the effective portion of gains or losses on derivative financial instruments that qualify as cash flow hedges pursuant to ASC 815, *Derivatives and Hedging* (“ASC 815”). For the three and nine months ended September 30, 2017, we reclassified an immaterial amount of losses from accumulated other comprehensive income (loss) to earnings. For additional information, see "Note 11—Derivatives.”

(3) Acquisition

On January 7, 2016, ENLK and ENLC acquired an 84% and 16% voting interest, respectively, in EnLink Oklahoma T.O. for approximately $1.4 billion. The first installment of $1.02 billion for the acquisition was paid at closing. The second installment of $250.0 million was paid on January 6, 2017, and the final installment of $250.0 million is due no later than January 7, 2018. The installment payables are valued net of discount within the total purchase price.

The first installment of approximately $1.02 billion was funded by (a) approximately $783.6 million in cash paid by ENLK, which was primarily derived from the issuance of Series B Cumulative Convertible Preferred Units (“Series B Preferred Units”), (b) 15,564,009 common units representing limited liability company interests in ENLC issued directly by ENLC and (c) approximately $22.2 million in cash paid by ENLC. The transaction was accounted for using the acquisition method.

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

Consideration:		
Cash	$	783.6
Total installment payable, net of discount of $79.1 million assuming payments made on January 7, 2017 and 2018		420.9
Contribution from ENLC		237.1
Total consideration	$	1,441.6
Purchase Price Allocation:		
Assets acquired:		
Current assets (including $12.8 million in cash)	$	23.0
Property, plant and equipment		406.1
Intangibles		1,051.3
Liabilities assumed:		
Current liabilities		(38.8)
Total identifiable net assets	$	1,441.6

The fair value of assets acquired and liabilities assumed are based on inputs that are not observable in the market and thus represent Level 3 inputs. We recognized intangible assets related to customer relationships and determined their fair value using the income approach. The acquired intangible assets are amortized on a straight-line basis over the estimated customer life of approximately 15 years.

We incurred a total of $4.1 million of direct transaction costs, of which $3.7 million was recognized as expense for the nine months ended September 30, 2016. These costs are included in general and administrative expenses in the accompanying consolidated statements of operations.

For the three and nine months ended September 30, 2016, we recognized $77.3 million and $149.5 million of revenues, respectively, and $4.4 million and $27.9 million of net loss, respectively, related to the assets acquired.

(4) Goodwill and Intangible Assets

Goodwill

Goodwill is the cost of an acquisition less the fair value of the net identifiable assets of the acquired business. The fair value of goodwill is based on inputs that are not observable in the market and thus represent Level 3 inputs. We evaluate goodwill for impairment annually as of October 31 and whenever events or changes in circumstances indicate it is more likely than not that the fair value of a reporting unit is less than its carrying amount.

We perform our goodwill assessments at the reporting unit level for all reporting units. We use a discounted cash flow analysis to perform the assessments. Key assumptions in the analysis include the use of an appropriate discount rate, terminal year multiples and estimated future cash flows, including volume and price forecasts and estimated operating and general and administrative costs. In estimating cash flows, we incorporate current and historical market and financial information, among other factors. Impairment determinations involve significant assumptions and judgments, and differing assumptions regarding any of these inputs could have a significant effect on the various valuations. If actual results are not consistent with our assumptions and estimates, or our assumptions and estimates change due to new information, we may be exposed to goodwill impairment charges, which would be recognized in the period in which the carrying value exceeds fair value.

During February 2016, we determined that weakness in the overall energy sector, driven by low commodity prices, together with a decline in our unit price, caused a change in circumstances warranting an interim impairment test. Based on these triggering events, we performed a goodwill impairment analysis in the first quarter of 2016 on all reporting units. Based on this analysis, a goodwill impairment loss for our Texas and Crude and Condensate reporting units in the amount of $566.3 million was recognized in the first quarter of 2016 and is included as an impairment loss on the consolidated statement of operations for the nine months ended September 30, 2016. We concluded that the fair value of our Oklahoma reporting unit exceeded its carrying value, and the amount of goodwill disclosed on the consolidated balance sheet associated with this reporting unit is recoverable. Therefore, no goodwill impairment was identified or recorded for this reporting unit as a result of our goodwill impairment analysis.

During the first quarter of 2017, we elected to early adopt ASU 2017-04, which simplifies the accounting for goodwill impairments by eliminating the requirement to compare the implied fair value of goodwill with its carrying amount as part of step two of the goodwill impairment test referenced in ASC 350. Although no goodwill impairment tests were required during the nine months ended September 30, 2017, we will perform future goodwill impairment tests according to ASU 2017-04. For additional information, see “Note 2—Significant Accounting Policies.”

Intangible Assets

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

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, 2017			
Customer relationships, beginning of period	$ 1,795.8	$ (171.6)	$ 1,624.2
Amortization expense	—	(96.2)	(96.2)
Customer relationships, end of period	$ 1,795.8	$ (267.8)	$ 1,528.0

The weighted average amortization period is 15.0 years. Amortization expense was approximately $31.2 million and $29.9 million for the three months ended September 30, 2017 and 2016, respectively, and $96.2 million and $87.4 million for the nine months ended September 30, 2017 and 2016, respectively.

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

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

2017 (remaining)	$ 30.8
2018	123.4
2019	123.4
2020	123.4
2021	123.4
Thereafter	1,003.6
Total	$ 1,528.0

(5) Related Party Transactions

We engage in various transactions with Devon and other related parties. For thethree and nine months ended September 30, 2017, Devon accounted for 15.0% and 15.4% of our revenues, respectively, and for thethree and nine months ended September 30, 2016, Devon accounted for 18.9% and 19.4% of our revenues, respectively. We had an accounts receivable balance related to transactions with Devon of $121.5 million at September 30, 2017 and $100.2 million at December 31, 2016. Additionally, we had an accounts payable balance related to transactions with Devon of $36.8 million at September 30, 2017 and $10.4 million at December 31, 2016. Management believes these transactions are executed on terms that are fair and reasonable and are consistent with terms for transactions with unrelated third parties. The amounts related to related party transactions are specified in the accompanying consolidated financial statements.

(6) Long-Term Debt

As of September 30, 2017 and December 31, 2016, long-term debt consisted of the following (in millions):

	September 30, 2017			December 31, 2016		
	Outstanding Principal	Premium (Discount)	Long-Term Debt	Outstanding Principal	Premium (Discount)	Long-Term Debt
Partnership credit facility due 2020 (1)	$ —	$ —	$ —	$ 120.0	$ —	$ 120.0
2.70% Senior unsecured notes due 2019	400.0	(0.2)	399.8	400.0	(0.3)	399.7
7.125% Senior unsecured notes due 2022	—	—	—	162.5	16.0	178.5
4.40% Senior unsecured notes due 2024	550.0	2.3	552.3	550.0	2.5	552.5
4.15% Senior unsecured notes due 2025	750.0	(1.0)	749.0	750.0	(1.1)	748.9
4.85% Senior unsecured notes due 2026	500.0	(0.6)	499.4	500.0	(0.7)	499.3
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	(6.5)	443.5	450.0	(6.6)	443.4
5.45% Senior unsecured notes due 2047	500.0	(0.1)	499.9	—	—	—
Debt classified as long-term	$ 3,500.0	$ (6.3)	$ 3,493.7	$ 3,282.5	$ 9.6	$ 3,292.1
Debt issuance cost (2)			(26.9)			(24.1)
Long-term debt, net of unamortized issuance cost			$ 3,466.8			$ 3,268.0

(1) Bears interest based on Prime and/or LIBOR plus an applicable margin. The effective interest rate was 2.3% at December 31, 2016.
(2) Net of amortization of $11.0 million and $8.3 million at September 30, 2017 and December 31, 2016, 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 zero percent 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. At September 30, 2017, 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, 2017, there were $9.2 million in outstanding letters of credit and no outstanding borrowings under our credit facility, leaving approximately $1.5 billion available for future borrowing.

All other material terms and conditions of our credit facility 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, 2016.

Senior Unsecured Notes due 2047

On May 11, 2017, we issued $500.0 million in aggregate principal amount of our 5.450% senior unsecured notes due June 1, 2047 (the "2047 Notes") at a price to the public of 99.981% of their face value. Interest payments on the 2047 Notes are payable on June 1 and December 1 of each year, beginning December 1, 2017. Net proceeds of approximately $495.2 million were used to repay outstanding borrowings under our credit facility and for general partnership purposes.

Redemption of Senior Unsecured Notes due 2022

On June 1, 2017, we redeemed $162.5 million in aggregate principal amount of our 7.125% senior unsecured notes (the "2022 Notes") at 103.6% of the principal amount, plus accrued unpaid interest, for aggregate cash consideration of $174.1 million, which resulted in a gain on extinguishment of debt of $9.0 million for the nine months ended September 30, 2017.

(7) Partners' Capital

(a) Issuance of Common Units

In November 2014, we entered into an Equity Distribution Agreement (the "2014 EDA") with BMO Capital Markets Corp., Merrill Lynch, Pierce, Fenner & Smith Incorporated, Citigroup Global Markets Inc., Jefferies LLC, Raymond James & Associates, Inc. and RBC Capital Markets, LLC to sell up to $350.0 million in aggregate gross sales of our common units from time to time through an "at the market" equity offering program.

In August 2017, we ceased trading under the 2014 EDA and entered into an Equity Distribution Agreement (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.

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

For the nine months ended September 30, 2017, we sold an aggregate of approximately 5.3 million common units under the 2014 EDA and 2017 EDA, generating proceeds of approximately $92.3 million (net of approximately $0.9 million of commissions and $0.2 million of registration fees). We used the net proceeds for general partnership purposes. As of September 30, 2017, approximately $580.1 million remains available to be issued under the 2017 EDA.

(b) Series B Preferred Units

In January 2016, we issued an aggregate of 50,000,000 Series B Preferred Units representing our limited partner interests to Enfield Holdings, L.P. ("Enfield") in a private placement for a cash purchase price of $15.00 per Series B Preferred Unit (the "Issue Price"), resulting in net proceeds of approximately $724.1 million after fees and deductions. Proceeds from the private placement were used to partially fund our portion of the purchase price payable in connection with the acquisition of our EnLink Oklahoma T.O. assets. Affiliates of the Goldman Sachs Group, Inc. and affiliates of TPG Global, LLC own interests in the general partner of Enfield. The Series B Preferred Units are convertible into our common units on a one-for-one basis, subject to certain adjustments (a) in full, at our option, if the volume weighted average price of a common unit over the 30-trading day period ending two trading days prior to the conversion date (the "Conversion VWAP") is greater than 150% of the Issue Price or (b) in full or in part, at Enfield's option. In addition, upon certain events involving a change of control of our general partner or the managing member of ENLC, all of the Series B Preferred Units will automatically convert into a number of common units equal to the greater of (i) the number of common units into which the Series B Preferred Units would then convert and (ii) the number of Series B Preferred Units to be converted multiplied by an amount equal to (x) 140% of the Issue Price divided by (y) the Conversion VWAP.

For the quarter ended March 31, 2016 through the quarter ended June 30, 2017, Enfield received a quarterly distribution equal to an annual rate of 8.5% on the Issue Price payable in-kind in the form of additional Series B Preferred Units. For the quarter ended September 30, 2017 and each subsequent quarter, Enfield is entitled to receive a quarterly distribution, subject to certain adjustments, equal to an annual rate of 7.5% on the Issue Price payable in cash (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.

A summary of the distribution activity relating to the Series B Preferred Units for the nine months ended September 30, 2017 and 2016 is provided below:

Declaration period	Distribution paid-in kind (1)	Cash Distribution (in millions)	Date paid/payable
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
2016			
First Quarter of 2016	992,445	$ —	May 12, 2016
Second Quarter of 2016	1,083,589	$ —	August 11, 2016
Third Quarter of 2016	1,106,616	$ —	November 10, 2016

(1) Represents distributions paid or payable on the Series B Preferred Units through issuance of additional Series B Preferred Units.

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

(c) Issuance of Series C Preferred Units

In September 2017, we issued 400,000 Series C Fixed-to-Floating Rate Cumulative Redeemable Perpetual Preferred Units (the "Series C Preferred Units") representing our limited partner interests at a price to the public of $1,000 per unit. We used the net proceeds of $393.7 million for capital expenditures, general partnership purposes and to repay borrowings under our credit facility. The Series C Preferred Units represent perpetual equity interests in us and, unlike our indebtedness, will not give rise to a claim for payment of a principal amount at a particular date. As to the payment of distributions and amounts payable on a liquidation event, the Series C Preferred Units rank senior to our common units and to each other class of limited partner interests or other equity securities established after the issue date of the Series C Preferred Units that is not expressly made senior or on parity with the Series C Preferred Units. The Series C Preferred Units will rank junior to the Series B Preferred Units with respect to the payment of distributions, and junior to the Series B Preferred Units and all current and future indebtedness with respect to amounts payable upon a liquidation event. Income is allocated to the Series C Preferred Units in an amount equal to the earned distributions for the respective reporting period.

At any time on or after December 15, 2022, we may redeem, at our option, in whole or in part, the Series C Preferred Units at a redemption price in cash equal to $1,000 per Series C Preferred Unit plus an amount equal to all accumulated and unpaid distributions, whether or not declared. We may undertake multiple partial redemptions. In addition, at any time within 120 days after the conclusion of any review or appeal process instituted by us following certain rating agency events, we may redeem, at our option, the Series C Preferred Units in whole at a redemption price in cash per unit equal to $1,020 plus an amount equal to all accumulated and unpaid distributions, whether or not declared.

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

(d) Common Unit Distributions

Unless restricted by the terms of our credit facility and/or the indentures governing our unsecured senior 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 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. Our 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 of our 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.

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

A summary of the distribution activity relating to the common units for the nine months ended September 30, 2017 and 2016 is provided below:

Declaration period	Distribution/unit	Date paid/payable
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
2016		
Fourth Quarter of 2015	$ 0.39	February 11, 2016
First Quarter of 2016	$ 0.39	May 12, 2016
Second Quarter of 2016	$ 0.39	August 11, 2016
Third Quarter of 2016	$ 0.39	November 11, 2016

(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 units for the periods presented (in millions, except per unit amounts):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
Limited partners' interest in net loss	$ (8.6)	$ (11.4)	$ (18.4)	$ (602.1)
Distributed earnings allocated to:				
Common units (1) (2)	$ 135.7	$ 131.5	$ 405.0	$ 387.0
Unvested restricted units (1) (2)	1.1	0.9	3.0	2.6
Total distributed earnings	$ 136.8	$ 132.4	$ 408.0	$ 389.6
Undistributed loss allocated to:				
Common units	$ (144.3)	$ (142.8)	$ (423.3)	$ (985.1)
Unvested restricted units	(1.1)	(1.0)	(3.1)	(6.6)
Total undistributed loss	$ (145.4)	$ (143.8)	$ (426.4)	$ (991.7)
Net loss allocated to:				
Common units	$ (8.6)	$ (11.3)	$ (18.3)	$ (598.1)
Unvested restricted units	—	(0.1)	(0.1)	(4.0)
Total limited partners' interest in net loss	$ (8.6)	$ (11.4)	$ (18.4)	$ (602.1)
Basic and diluted net loss per unit:				
Basic	$ (0.02)	$ (0.03)	$ (0.05)	$ (1.82)
Diluted	$ (0.02)	$ (0.03)	$ (0.05)	$ (1.82)

(1) For the three months ended September 30, 2017 and 2016, distributed earnings included a declared distribution of $0.39 per unit payable on November 13, 2017 and a distribution of $0.39 per unit paid on November 11, 2016, respectively.
(2) For the nine months ended September 30, 2017, distributed earnings included a declared distribution of 0.39 per unit payable on November 13, 2017 and distributions of $0.39 per unit paid on August 11, 2017 and $0.39 per unit paid on May 12, 2017. For the nine months ended September 30, 2016, distributed earnings included distributions of $0.39 per unit paid on November 11, 2016, $0.39 per unit paid on August 11, 2016 and $0.39 per unit paid on May 12, 2016.

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

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
Basic weighted average units outstanding:				
Weighted average limited partner basic common units outstanding (1)	347.9	337.2	346.1	330.8
Diluted weighted average units outstanding:				
Weighted average limited partner basic common units outstanding (1)	347.9	337.2	346.1	330.8
Dilutive effect of non-vested restricted units (2)	—	—	—	—
Dilutive effect of convertible Series B Preferred Units (2)	—	—	—	—
Total weighted average limited partner diluted common units outstanding	347.9	337.2	346.1	330.8

(1) For the three and nine months ended September 30, 2016, weighted average limited partner basic common units outstanding included the weighted average impact of 3,645,688 Class C Common Units that converted into common units on May 13, 2016.
(2) All common unit equivalents were antidilutive for the three and nine months ended September 30, 2017 and 2016 because the limited partners were allocated a net loss.

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 (d) 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,	
	2017	2016	2017	2016
Income allocation for incentive distributions	$ 14.8	$ 14.4	$ 44.1	$ 42.4
Unit-based compensation attributable to ENLC's restricted units	(4.2)	(3.6)	(16.9)	(11.2)
General partner share of net income (loss)	—	—	0.1	(2.4)
General partner interest in net income	$ 10.6	$ 10.8	$ 27.3	$ 28.8

(8) Asset Retirement Obligations

The schedule below summarizes the changes in our asset retirement obligations (in millions):

Nine Months Ended September 30, 2017	
Balance, beginning of period	$ 13.5
Accretion expense	0.5
Balance, end of period	$ 14.0

Asset retirement obligations of $14.0 million and $13.5 million were included in "Asset retirement obligations" as non-current liabilities on the consolidated balance sheets as of September 30, 2017 and December 31, 2016, respectively.

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

(9) Investment in Unconsolidated Affiliates

Our unconsolidated investments consisted of:

- a contractual right to the economic benefits and burdens associated with Devon's 38.75% ownership interest in Gulf Coast Fractionators ("GCF") at September 30, 2017 and December 31, 2016;
- an approximate 30% ownership in Cedar Cove Midstream LLC (the "Cedar Cove JV") at September 30, 2017 and December 31, 2016. On November 9, 2016, we formed the Cedar Cove JV with Kinder Morgan, Inc., which consists of gathering and compression assets in Blaine County, Oklahoma, the heart of the Sooner Trend Anadarko Basin Canadian and Kingfisher Counties play; and
- an approximate 31% common unit ownership interest in Howard Energy Partners ("HEP") at December 31, 2016, which was sold in March 2017 for aggregate net proceeds of $189.7 million.

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,	
	2017	2016	2017	2016
Gulf Coast Fractionators				
Contributions	$ —	$ —	$ —	$ —
Distributions	$ 3.5	$ 0.9	$ 10.6	$ 4.4
Equity in income	$ 4.5	$ 2.2	$ 8.5	$ 1.1
Howard Energy Partners				
Contributions (1)	$ —	$ 3.2	$ —	$ 45.0
Distributions (2)	$ —	$ 36.5	$ —	$ 47.9
Equity in loss (3)	$ —	$ (1.1)	$ (3.4)	$ (1.6)
Cedar Cove JV				
Contributions	$ 1.5	$ —	$ 11.8	$ —
Distributions	$ 0.5	$ —	$ 0.8	$ —
Equity in loss	$ (0.1)	$ —	$ (0.1)	$ —
Total				
Contributions (1)	$ 1.5	$ 3.2	$ 11.8	$ 45.0
Distributions (2)	$ 4.0	$ 37.4	$ 11.4	$ 52.3
Equity in income (loss) (3)	$ 4.4	$ 1.1	$ 5.0	$ (0.5)

(1) Contributions for the three and nine months ended September 30, 2016 included $3.2 million and $32.7 million, respectively, of contributions to HEP for preferred units issued by HEP, which were redeemed during the third quarter of 2016.
(2) Distributions for the three and nine months ended September 30, 2016 included a redemption of $32.7 million of preferred units issued by HEP.
(3) Includes a loss of $3.4 million for the nine months ended September 30, 2017 from the sale of our HEP interests.

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

The following table shows the balances related to our investment in unconsolidated affiliates as of September 30, 2017 and December 31, 2016 (in millions):

	September 30, 2017	December 31, 2016
Gulf Coast Fractionators	$ 46.4	$ 48.5
Howard Energy Partners	—	193.1
Cedar Cove JV	39.7	28.8
Total investment in unconsolidated affiliates	$ 86.1	$ 270.4

(10) 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 “LLC 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 on the consolidated financial statements. Unit-based compensation cost 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 our officers and employees is recorded by us since ENLC has no substantial or managed operating activities other than its interests in us and EnLink Oklahoma T.O. 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,	
	2017	2016	2017	2016
Cost of unit-based compensation charged to general and administrative expense	$ 7.3	$ 5.7	$ 28.3	$ 17.5
Cost of unit-based compensation charged to operating expense	2.8	1.6	10.4	5.0
Total unit-based compensation expense	$ 10.1	$ 7.3	$ 38.7	$ 22.5

(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 the common units on such date. A summary of the restricted incentive unit activity for the nine months ended September 30, 2017 is provided below:

	Nine Months Ended September 30, 2017	
EnLink Midstream Partners, LP Restricted Incentive Units:	**Number of Units**	**Weighted Average Grant-Date Fair Value**
Non-vested, beginning of period	2,024,820	$ 19.05
Granted (1)	859,595	18.41
Vested (1)(2)	(851,753)	25.90
Forfeited	(32,225)	16.28
Non-vested, end of period	2,000,437	$ 15.91
Aggregate intrinsic value, end of period (in millions)	$ 33.5	

(1) Restricted incentive units typically vest at the end of three years. In March 2017, we granted 262,288 restricted incentive units with a fair value of $5.1 million to officers and certain employees as bonus payments for 2016, and these restricted incentive units vested immediately and are included in the restricted incentive units granted and vested line items.
(2) Vested units included 273,848 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, 2017 and 2016 is provided below (in millions):

	Three Months Ended September 30,		Nine Months Ended September 30,	
EnLink Midstream Partners, LP Restricted Incentive Units:	**2017**	**2016**	**2017**	**2016**
Aggregate intrinsic value of units vested	$ 0.6	$ 0.3	$ 16.3	$ 4.1
Fair value of units vested	$ 1.1	$ 0.5	$ 22.1	$ 9.5

As of September 30, 2017, there was $14.6 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 1.7 years.

(c) EnLink Midstream Partners, LP Performance Units

For the nine months ended September 30, 2017, our general partner and EnLink Midstream Manager, LLC, the managing member of ENLC, granted performance awards under the GP Plan and the LLC Plan, respectively. The performance award agreements provide that the vesting of 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 Alerian MLP Index for Master Limited Partnerships ("AMZ"), excluding ENLK and ENLC (collectively, "EnLink"), 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 range 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 group securities; (iii) an estimated ranking of us among the designated peer group; 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 Partners, LP Performance Units:	**March 2017**
Beginning TSR Price	$ 17.55
Risk-free interest rate	1.62%
Volatility factor	43.94%
Distribution yield	8.7%

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

The following table presents a summary of the performance units:

	Nine Months Ended September 30, 2017	
EnLink Midstream Partners, LP Performance Units:	**Number of Units**	**Weighted Average Grant-Date Fair Value**
Non-vested, beginning of period	408,637	$ 18.27
Granted	176,648	25.73
Forfeited	—	—
Non-vested, end of period	585,285	$ 20.52
Aggregate intrinsic value, end of period (in millions)	$ 9.8	

As of September 30, 2017, there was $5.9 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 1.9 years.

(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 the ENLC common units on such dateA summary of the restricted incentive unit activity for the nine months ended September 30, 2017 is provided below:

	Nine Months Ended September 30, 2017	
EnLink Midstream, LLC Restricted Incentive Units:	**Number of Units**	**Weighted Average Grant-Date Fair Value**
Non-vested, beginning of period	1,897,298	$ 19.96
Granted (1)	817,201	19.24
Vested (1)(2)	(775,973)	28.28
Forfeited	(31,636)	16.53
Non-vested, end of period	1,906,890	$ 16.32
Aggregate intrinsic value, end of period (in millions)	$ 32.9	

(1) Restricted incentive units typically vest at the end of three years. In March 2017, ENLC granted 258,606 restricted incentive units with a fair value of $5.0 million to officers and certain employees as bonus payments for 2016, and these restricted incentive units vested immediately and are included in the restricted incentive units granted and vested line items.
(2) Vested units included 238,312 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, 2017 and 2016 is provided below (in millions):

	Three Months Ended September 30,		Nine Months Ended September 30,	
EnLink Midstream, LLC Restricted Incentive Units:	**2017**	**2016**	**2017**	**2016**
Aggregate intrinsic value of units vested	$ 0.6	$ 0.3	$ 15.2	$ 4.1
Fair value of units vested	$ 1.1	$ 0.6	$ 21.9	$ 12.4

As of September 30, 2017, there was $14.2 million of unrecognized compensation cost related to non-vested ENLC restricted incentive units. The cost is expected to be recognized over a weighted-average period of 1.8 years.

(e) EnLink Midstream, LLC's Performance Units

For the nine months ended September 30, 2017, ENLC granted performance awards under the LLC Plan. 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 range 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 group securities; (iii) an estimated ranking of ENLC among the designated peer group 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 2017
Beginning TSR Price	$ 18.29
Risk-free interest rate	1.62%
Volatility factor	52.07%
Distribution yield	5.4%

The following table presents a summary of the performance units:

	Nine Months Ended September 30, 2017	
EnLink Midstream, LLC Performance Units:	Number of Units	Weighted Average Grant-Date Fair Value
Non-vested, beginning of period	384,264	$ 19.30
Granted	164,575	28.77
Forfeited	—	—
Non-vested, end of period	548,839	$ 22.14
Aggregate intrinsic value, end of period (in millions)	$ 9.5	

As of September 30, 2017, 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 2.0 years.

(11) 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 on the consolidated statements of operations.

In May 2017, we entered into an interest rate swap in connection with the issuance of 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 other 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. We have no open interest rate swap positions as of September 30, 2017. In addition, the settlement loss is included as an operating cash outflow on the consolidated statements of cash flows.

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

For the three and nine months ended September 30, 2017, 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.

In July 2016, we entered into an interest rate swap in connection with the issuance of the 4.85% senior unsecured notes due 2026. We did not designate this swap as a cash flow hedge. Upon settlement of the interest rate swap in July 2016, we recorded the associated $0.4 million gain on settlement in other income (expense) in the consolidated statements of operations for the three and nine months ended September 30, 2016.

Commodity Swaps

We manage our exposure to changes in commodity prices by hedging the impact of market fluctuations. Commodity swaps are used to manage and hedge price and location risk related to these market exposures. Commodity swaps are also used 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 swap transactions 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 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, 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.

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
Change in fair value of derivatives	$ (3.3)	$ (1.6)	$ 3.8	$ (16.0)
Realized gain (loss) on derivatives	(2.2)	1.1	(4.9)	9.4
Loss on derivative activity	$ (5.5)	$ (0.5)	$ (1.1)	$ (6.6)

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

	September 30, 2017	December 31, 2016
Fair value of derivative assets — current	$ 4.6	$ 1.3
Fair value of derivative assets — long-term	0.1	—
Fair value of derivative liabilities — current	(7.2)	(7.6)
Net fair value of derivatives	$ (2.5)	$ (6.3)

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.

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, 2017 (in millions). The remaining term of the contracts extend no later than October 2018.

		September 30, 2017		
Commodity	**Instruments**	**Unit**	**Volume**	**Fair Value**
NGL (short contracts)	Swaps	Gallons	(35.8)	$ (4.9)
NGL (long contracts)	Swaps	Gallons	25.1	1.9
Natural Gas (short contracts)	Swaps	MMBtu	(20.5)	1.3
Natural Gas (long contracts)	Swaps	MMBtu	23.2	(0.7)
Condensate (short contracts)	Swaps	MMbbls	0.1	(0.1)
Total fair value of derivatives				$ (2.5)

On all transactions where we are exposed to counterparty risk, we analyze the counterparty's financial condition prior to entering into an agreement, establish limits and monitor the appropriateness of these limits on an ongoing basis. We primarily deal with two types of counterparties, financial institutions and other energy companies, when entering into financial derivatives on commodities. We have entered into Master International Swaps and Derivatives Association Agreements ("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, our maximum loss of $4.7 million as of September 30, 2017 would be reduced to$1.7 million due to the offsetting of gross fair value payables against gross fair value receivables as allowed by the ISDAs.

(12) 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, 2017	**December 31, 2016**
Commodity Swaps (1)	$ (2.5)	$ (6.3)
Total	$ (2.5)	$ (6.3)

(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, 2017		December 31, 2016	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Long-term debt (1)	$ 3,466.8	$ 3,564.7	$ 3,268.0	$ 3,225.8
Installment Payables	$ 243.0	$ 243.7	$ 473.2	$ 476.6
Obligations under capital lease	$ 4.4	$ 3.7	$ 6.6	$ 6.1

(1) The carrying value of long-term debt is reduced by debt issuance costs of $26.9 million and $24.1 million at September 30, 2017 and December 31, 2016, 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 no outstanding borrowings under our credit facility as of September 30, 2017 and $120.0 million of outstanding borrowings under our credit facility as of December 31, 2016. 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, 2017 and December 31, 2016, we had total borrowings under senior unsecured notes of $3.5 billion and $3.1 billion, respectively, maturing between 2019 and 2047 with fixed interest rates ranging from2.7% to 5.6% and 2.7% to 7.1%, respectively. The fair values of all senior unsecured notes and installment payables as of September 30, 2017 and December 31, 2016 were based on Level 2 inputs from third-party market quotations. The fair values of obligations under capital leases were calculated using Level 2 inputs from third-party banks.

(13) Commitments and Contingencies

(a) Severance and Change in Control Agreements

Certain members of our management are parties to severance and change of control agreements with the Operating Partnership. The severance and change in control agreements provide those individuals with severance payments in certain circumstances and prohibit such individuals from, among other things, competing with our general partner or its affiliates during his or her employment. In addition, the severance and change of control agreements prohibit subject individuals from, among other things, disclosing confidential information about our general partner or its affiliates or interfering with a client or customer of our general partner or its affiliates, in each case during his or her employment and for certain periods (including indefinite periods) following the termination of such person’s employment.

(b) Environmental Issues

The operation of pipelines, plants and other facilities for the gathering, processing, transmitting, stabilizing, fractionating, storing or disposing of natural gas, NGLs, crude oil, condensate, brine and other products is subject to stringent and complex laws and regulations pertaining to health, safety and the environment. As an owner, partner or operator of these facilities, we must comply with United States laws and regulations at the federal, state and local levels that relate to air and water quality, hazardous and solid waste management and disposal, oil spill prevention, climate change, endangered species and other environmental matters. The cost of planning, designing, constructing and operating pipelines, plants, and other facilities must account for compliance with environmental laws and regulations and safety standards. Federal, state, or local administrative decisions, developments in the federal or state court systems, or other governmental or judicial actions may influence the interpretation and enforcement of environmental laws and regulations and may thereby increase compliance costs. Failure to comply with these laws and regulations may trigger a variety of administrative, civil and potentially criminal enforcement measures, including citizen suits, which can include the assessment of monetary penalties, the imposition of remedial requirements and the issuance of injunctions or restrictions on operation. Management believes that, based on currently known information, compliance with these laws and regulations will not have a material adverse effect on our results of operations, financial condition or cash flows. However, we cannot provide assurance that future events, such as changes in existing laws, regulations, or enforcement policies, the promulgation of new laws or regulations, or the discovery or development of new factual circumstances will not cause us to incur material costs. Environmental regulations have historically become more stringent over time and, thus, there can be no assurance as to the amount or timing of future expenditures for environmental compliance or remediation.

In the second quarter of 2017, we reached a settlement agreement with the Ohio Environmental Protection Agency with respect to the previously disclosed notices of violation (“NOVs”) relating to certain of our ORV operations that were previously operated by a joint venture partner. The settlement payment is not material to our results of operations, financial condition or cash flows.

On July 29, 2016, after concluding a multi-year internal environmental compliance assessment of our Louisiana operations, we commenced discussions with the Louisiana Department of Environmental Quality (“LDEQ”) relating to: (a) a global settlement to resolve environmental noncompliance discovered or investigated during our assessment involving several of our Louisiana facilities and (b) notices of potential violation and NOVs received from the LDEQ. We have taken appropriate measures to resolve all instances of noncompliance. In the third quarter of 2017, we reached a global settlement with the LDEQ pursuant to which we paid approximately $0.3 million.

As part of our ongoing environmental and regulatory compliance efforts, we discovered instances of non-compliance with certain environmental regulations at one of our north Texas plants and self-reported these matters to the Texas Commission on Environment Quality (“TCEQ”). On October 4, 2017, we received and accepted an Agreed Order from the TCEQ related to these instances of non-compliance. The final penalty assessed was not material to the results of our operations, financial condition or cash flows.

Finally, we continue to await a ruling from the Pipeline and Hazardous Materials Safety Administration regarding the notice of potential violation discussed in our Annual Report on Form 10-K for the year ended December 31, 2016.

(c) Litigation Contingencies

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.

In July 2013, the Board of Commissioners for the Southeast Louisiana Flood Protection Authority for New Orleans and surrounding areas filed a lawsuit against approximately 100 energy companies, seeking, among other relief, restoration of wetlands allegedly lost due to historic industry operations in those areas. The suit was filed in Louisiana state court in New Orleans but was removed to the United States District Court for the Eastern District of Louisiana. The amount of damages is unspecified. Our subsidiary, EnLink LIG, LLC, is one of the named defendants as the owner of pipelines in the area. On February 13, 2015, the court granted defendants’ joint motion to dismiss and dismissed the plaintiff’s claims with prejudice. Plaintiffs appealed the matter to the United States Court of Appeals for the Fifth Circuit. On March 3, 2017, the Court of Appeals affirmed the district court’s dismissal of the plaintiff’s claims. On March 17, 2017, the plaintiff filed a petition for rehearing. On April 12, 2017, the Court of Appeals denied the plaintiffs petition for rehearing. On July 11, 2017, the plaintiffs filed a petition for appeal with the United States Supreme Court, which was denied on October 30, 2017.

We own and operate a high-pressure pipeline and underground natural gas and NGL storage reservoirs and associated facilities near Bayou Corne, Louisiana. In August 2012, a large sinkhole formed in the vicinity of this pipeline and underground storage reservoirs, resulting in damage to certain of our facilities. In order to recover our losses from responsible parties, we sued the operator of a failed cavern in the area, and its insurers, seeking recovery for these losses, as well as other parties we alleged contributed to the formation of the sinkhole. We also filed a claim with our insurers, which our insurers denied. We disputed the denial and sued our insurers. We have reached settlements regarding the entirety of our claims in both lawsuits. In August 2014, we received a partial settlement with respect to our claims in the amount of $6.1 million. We secured additional settlement payments in aggregate amounts of $17.5 million and $8.5 million in March 2017 and June 2017, respectively, which resulted in the recognition of “Gain on litigation settlement” on the consolidated statements of operations of $26.0 million for the nine months ended September 30, 2017.

In June 2014, a group of landowners in Assumption Parish, Louisiana added our subsidiary, EnLink Processing Services, LLC, as a defendant in a pending lawsuit in the 23rd Judicial Court, Assumption Parish, Louisiana they had filed against other defendants relating to claims arising from the Bayou Corne Sinkhole. Plaintiffs alleged that EnLink Processing Services, LLC's negligence contributed to the formation of the sinkhole. The amount of damages was unspecified. EnLink Processing Services, LLC reached a settlement with the plaintiffs in February 2017, funded by EnLink Processing Services, LLC's insurance carriers. The plaintiffs' claims against EnLink Processing Services, LLC were dismissed with prejudice in March 2017.

(14) 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 Midland and Delaware basins in west Texas ("Texas"), the pipelines, processing plants, storage facilities and NGL 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 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 operating revenues and 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 as of September 30, 2017 and December 31, 2016. As of December 31, 2016, our Corporate assets included our unconsolidated affiliate investment in HEP. In December 2016, we entered into an agreement to sell our ownership interest in HEP, and we finalized the sale in March 2017.

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, 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
Three Months Ended September 30, 2016						
Product sales	$ 61.3	$ 430.9	$ 16.2	$ 262.6	$ —	$ 771.0
Product sales—related parties	81.9	24.4	36.0	—	(99.2)	43.1
Midstream services	27.5	57.2	24.2	16.8	—	125.7
Midstream services—related parties	109.5	29.9	47.7	5.2	(27.0)	165.3
Cost of sales	(134.1)	(471.5)	(58.3)	(250.5)	126.2	(788.2)
Operating expenses	(42.9)	(23.5)	(12.6)	(19.0)	—	(98.0)
Loss on derivative activity	—	—	—	—	(0.5)	(0.5)
Segment profit (loss)	$ 103.2	$ 47.4	$ 53.2	$ 15.1	$ (0.5)	$ 218.4
Depreciation and amortization	$ (48.7)	$ (28.8)	$ (35.6)	$ (10.7)	$ (2.4)	$ (126.2)
Goodwill	$ 232.0	$ —	$ 190.3	$ —	$ —	$ 422.3
Capital expenditures	$ 51.8	$ 15.4	$ 58.3	$ 12.8	$ 8.6	$ 146.9

	Texas	Louisiana	Oklahoma	Crude and Condensate	Corporate	Totals
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
Nine Months Ended September 30, 2016						
Product sales	$ 165.7	$ 1,118.1	$ 32.9	$ 781.1	$ —	$ 2,097.8
Product sales—related parties	191.9	47.0	69.1	1.1	(209.8)	99.3
Midstream services	78.1	165.1	57.3	48.0	—	348.5
Midstream services—related parties	331.7	68.1	134.4	14.4	(60.1)	488.5
Cost of sales	(329.0)	(1,199.1)	(109.2)	(739.4)	269.9	(2,106.8)
Operating expenses	(125.2)	(72.2)	(37.2)	(61.7)	—	(296.3)
Loss on derivative activity	—	—	—	—	(6.6)	(6.6)
Segment profit (loss)	$ 313.2	$ 127.0	$ 147.3	$ 43.5	$ (6.6)	$ 624.4
Depreciation and amortization	$ (143.6)	$ (86.7)	$ (104.2)	$ (31.7)	$ (6.8)	$ (373.0)
Impairments	$ (473.1)	$ —	$ —	$ (93.2)	$ —	$ (566.3)
Goodwill	$ 232.0	$ —	$ 190.3	$ —	$ —	$ 422.3
Capital expenditures	$ 132.3	$ 52.2	$ 190.6	$ 17.0	$ 15.4	$ 407.5

The table below represents information about segment assets as ofSeptember 30, 2017 and December 31, 2016 (in millions):

Segment Identifiable Assets:	September 30, 2017	December 31, 2016
Texas	$ 3,113.0	$ 3,142.6
Louisiana	2,395.5	2,349.3
Oklahoma	2,814.7	2,524.5
Crude and Condensate	847.2	836.8
Corporate	255.7	300.2
Total identifiable assets	$ 9,426.1	$ 9,153.4

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

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
Segment profits	$ 242.6	$ 218.4	$ 686.7	$ 624.4
General and administrative expenses	(30.0)	(28.3)	(94.6)	(90.6)
Gain (loss) on disposition of assets	(1.1)	3.0	(0.8)	2.9
Depreciation and amortization	(136.3)	(126.2)	(407.1)	(373.0)
Impairments	(1.8)	—	(8.8)	(566.3)
Gain on litigation settlement	—	—	26.0	—
Operating income (loss)	$ 73.4	$ 66.9	$ 201.4	$ (402.6)

(15) Supplemental Cash Flow Information

The following schedule summarizes non-cash financing activities for the periods presented (in millions):

	Nine Months Ended September 30,	
Non-cash financing activities:	2017	2016
Installment payable, net of discount of $79.1 million (1)	$ —	$ 420.9
Contribution from ENLC (2)	—	237.1

(1) We incurred installment purchase obligations, net of discount, payable to the seller in connection with the EnLink Oklahoma T.O. assets. We paid the first installment on January 6, 2017 and will pay the final installment no later than January 7, 2018. See "Note 3—Acquisition" for further discussion.
(2) Contribution from ENLC in connection with the acquisition of EnLink Oklahoma T.O. assets. See "Note 3—Acquisition" for further discussion.

(16) Other Information

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

	September 30, 2017	December 31, 2016
Natural gas and NGLs inventory	$ 59.1	$ 17.4
Prepaid expenses and other	13.9	13.6
Natural gas and NGLs inventory, prepaid expenses and other	$ 73.0	$ 31.0

	September 30, 2017	December 31, 2016
Accrued interest	$ 64.7	$ 34.2
Accrued wages and benefits, including taxes	23.2	19.0
Accrued ad valorem taxes	33.5	23.5
Capital expenditure accruals	43.6	64.6
Onerous performance obligations	15.4	15.9
Other	54.1	59.8
Other current liabilities	$ 234.5	$ 217.0

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

You should 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 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 EnLink Midstream Operating, L.P. and EnLink Oklahoma Gas Processing, LP ("EnLink Oklahoma T.O."). EnLink Oklahoma T.O. is sometimes used to refer to EnLink Oklahoma Gas Processing, LP itself or EnLink Oklahoma Gas Processing, LP together with its consolidated subsidiaries.

Overview

We are a Delaware limited partnership formed on July 12, 2002. We primarily focus on providing midstream energy services, including gathering, processing, transmission, fractionation, storage, condensate stabilization, brine services and marketing to producers of natural gas, NGLs, crude oil and condensate. Our midstream energy asset network includes approximately 11,000 miles of pipelines, 20 natural gas processing plants with approximately 4.5 billion cubic feet per day of processing capacity, 7 fractionators with approximately 260,000 barrels per day 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, transmission and fractionation operations in north Texas and the Midland and Delaware basins in west Texas;

- *Oklahoma Segment*. The Oklahoma segment includes our natural gas gathering and processing activities in Cana-Woodford, Arkoma-Woodford, Northern Oklahoma Woodford, Sooner Trend Anadarko Basin Canadian and Kingfisher Counties ("STACK"), South Central Oklahoma Oil Province ("SCOOP") and Central Northern Oklahoma Woodford Shale areas;

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

- *Crude and Condensate Segment*. The Crude and Condensate segment includes our Ohio River Valley ("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 and our crude oil activities associated with our Victoria Express Pipeline and related truck terminal and storage assets 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 contractual right to the economic burdens and benefits associated with Devon's ownership interest in Gulf Coast Fractionators ("GCF") in south Texas and our general partnership property and expenses. Until March 2017, the Corporate segment included our unconsolidated affiliate investment in Howard Energy Partners ("HEP"). In December 2016, we entered into an agreement to sell our ownership interest in HEP, and we finalized the sale in March 2017.

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 contractual arrangements, which include stated fixed-fee contract arrangements or arrangements where we purchase and resell commodities in connection with providing the related service and earn a net margin as our fee. While our transactions vary in form, the essential element of each transaction is the use of our assets to transport a product or provide a processed product to an end-user at the tailgate of the plant, barge terminal or pipeline. 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 95% of our gross operating margin was derived from fee-based services with no direct commodity exposure for the nine months ended September 30, 2017. We reflect revenue as "Product sales" and "Midstream services" on the consolidated statements of operations.

We generate revenues from eight primary sources:

- gathering and transporting natural gas and NGLs 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 gas, crude, 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;
- crude oil and condensate handled at our crude terminals;
- crude oil and condensate gathered, transported, purchased and sold;
- brine disposed;
- condensate stabilized; and
- gas, crude, and NGLs stored.

We typically gather, transport or store gas owned by others for a fee based on the volume of gas gathered, transported or stored. We also buy natural gas from producers, plants or shippers at either a fixed discount to a market index or a percentage of the market index, and then transport and resell the natural gas at the same market index. The fixed discount difference to a market index represents the fee for using our assets. 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. Our gathering and transportation fee related to a percentage of the index price can be adversely affected by declines in the price of natural gas. 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 to 2019 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, 2017, the balance sheet reflects a liability of $31.4 million related to this performance obligation. Narrower 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 transport and fractionate or store NGLs owned by others for a fee based on the volume of NGLs transported and fractionated or stored. We also buy mixed NGLs from our suppliers 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. The operating results of our NGL fractionation business are 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 typically gather or transport crude oil and condensate owned by others by rail, truck, pipeline and barge facilities for a net fee-based margin. We also buy crude oil and condensate from a producer at a fixed discount to a market index, 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 fee we will receive for each crude oil and condensate transaction.

We realize gross operating margins from our processing services primarily through different contractual arrangements: processing margins ("margin"), percentage of liquids ("POL"), percentage of proceeds ("POP") or fixed-fee based. 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. See "Item 3. Quantitative and Qualitative Disclosures about Market Risk—Commodity Price Risk."

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 the asset.

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

Organic Growth

Black Coyote Crude Oil Gathering System. We are expanding in the core of the STACK play in Central Oklahoma with the construction of a new crude oil gathering system that we refer to as "Black Coyote." Black Coyote will primarily be built on dedicated acreage from Devon, who will be the main shipper on the system. The system is expected to be operational in the first quarter of 2018.

Chisholm Plants. In April 2017, we completed construction of a new cryogenic gas processing plant, referred to as Chisholm II, which provides 200 MMcf/d of processing capacity and is tied to new and existing pipelines in the STACK and SCOOP plays in Oklahoma. The new capacity is supported by new and existing long-term contracts.

In addition, we commenced construction of a new processing plant referred to as Chisholm III in April 2017. Chisholm III will provide an additional 200 MMcf/d of processing capacity and will be tied to new and existing pipelines in the STACK and SCOOP plays. Construction is scheduled to be completed during the fourth quarter of 2017.

Greater Chickadee Crude Oil Gathering System. In March 2017, we completed construction and began operations of a crude oil gathering system in Upton and Midland counties, Texas in the Permian Basin that we refer to as "Greater Chickadee." Greater Chickadee includes over 185 miles of high- and low-pressure pipelines that transport crude oil volumes to several major market outlets and other key hub centers in the Midland, Texas area. Greater Chickadee also includes multiple central tank batteries, together with pump, truck injection and storage stations to maximize shipping and delivery options for our producer customers.

Marathon Petroleum Joint Venture. In March 2017, we completed construction and began operating a new NGL pipeline, which is part of our 50/50 joint venture with a subsidiary of Marathon Petroleum Company ("Marathon Petroleum"). This joint venture, Ascension Pipeline Company, LLC (the "Ascension JV"), is a bolt-on project to our Cajun-Sibon NGL system and is supported by long-term, fee-based contracts with Marathon Petroleum.

Lobo Natural Gas Gathering and Processing Facilities. The Lobo facilities are part of our joint venture (the "Delaware Basin JV") with an affiliate of NGP Natural Resources XI, LP ("NGP"). In the first quarter of 2017, we completed the expansion of a 75-mile gathering system located in Texas and New Mexico for our Lobo II processing facility. In the second quarter of 2017, we completed the construction of an additional expansion of the Lobo II processing facility, which provides an additional 60 MMcf/d of processing capacity. Furthermore, we are constructing an additional expansion to Lobo II, which will increase capacity by 30 MMcf/d and is expected to be completed during the fourth quarter of 2017.

In addition, we will be expanding the gas processing capacity at our Lobo facilities by 200 MMcf/d through construction of the Lobo III processing facility, which is expected to be operational by the second half of 2018.

Sale of Non-Core Assets

In March 2017, we finalized the sale of our ownership interest in HEP for net proceeds of $189.7 million. For the year ended December 31, 2016, we recorded an impairment loss of $20.1 million to reduce the carrying value of our investment to the expected sales price. Upon the final sale of HEP in March 2017, we recorded an additional loss of $3.4 million for the nine months ended September 30, 2017.

Senior Unsecured Notes due 2047

On May 11, 2017, we issued $500.0 million in aggregate principal amount of our 5.450% senior unsecured notes due June 1, 2047 (the "2047 Notes") at a price to the public of 99.981% of their face value. Interest payments on the 2047 Notes are payable on June 1 and December 1 of each year, beginning December 1, 2017. Net proceeds of approximately $495.2 million were used to repay outstanding borrowings under our credit facility and for general partnership purposes.

Redemption of Senior Unsecured Notes due 2022

On June 1, 2017, we redeemed $162.5 million in aggregate principal amount of our 7.125% senior unsecured notes (the "2022 Notes") at 103.6% of the principal amount, plus accrued unpaid interest, for aggregate cash consideration of $174.1 million, which resulted in a gain on extinguishment of debt of $9.0 million for the nine months ended September 30, 2017.

Issuance of Common Units

In November 2014, we entered into an Equity Distribution Agreement (the "2014 EDA") with BMO Capital Markets Corp. and other sales agents to sell up to $350.0 million in aggregate gross sales of our common units from time to time through an "at the market" equity offering program.

In August 2017, we ceased trading under the 2014 EDA and entered into an Equity Distribution Agreement (the "2017 EDA") with UBS Securities LLC and other sales agents (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, 2017, we sold an aggregate of approximately 5.3 million common units under the 2014 EDA and 2017 EDA, generating proceeds of approximately $92.3 million (net of approximately $0.9 million of commissions and $0.2 million of registration fees). We used the net proceeds for general partnership purposes. As of September 30, 2017, approximately $580.1 million remains available to be issued under the 2017 EDA.

Issuance of Series C Preferred Units

In September 2017, we issued 400,000 Series C Fixed-to-Floating Rate Cumulative Redeemable Perpetual Preferred Units (the "Series C Preferred Units") representing our limited partner interests at a price to the public of $1,000 per unit. We used the net proceeds of $393.7 million for capital expenditures, general partnership purposes and to repay borrowings under our credit facility. The Series C Preferred Units represent perpetual equity interests in us and, unlike our indebtedness, will not give rise to a claim for payment of a principal amount at a particular date. As to the payment of distributions and amounts payable on a liquidation event, the Series C Preferred Units rank senior to our common units and to each other class of limited partner interests or other equity securities established after the issue date of the Series C Preferred Units that is not expressly made senior or on parity with the Series C Preferred Units. The Series C Preferred Units will rank junior to the Series B Preferred Units with respect to the payment of distributions, and junior to the Series B Preferred Units and all current and future indebtedness with respect to amounts payable upon a liquidation event. Income is allocated to the Series C Preferred Units in an amount equal to the earned distributions for the respective reporting period.

At any time on or after December 15, 2022, we may redeem, at our option, in whole or in part, the Series C Preferred Units at a redemption price in cash equal to $1,000 per Series C Preferred Unit plus an amount equal to all accumulated and unpaid distributions, whether or not declared. We may undertake multiple partial redemptions. In addition, at any time within 120 days after the conclusion of any review or appeal process instituted by us following certain rating agency events, we may redeem, at our option, the Series C Preferred Units in whole at a redemption price in cash per unit equal to $1,020 plus an amount equal to all accumulated and unpaid distributions, whether or not declared.

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

Non-GAAP Financial Measures

We include the following non-GAAP financial measures: Adjusted earnings before interest, taxes, 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 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 acquisition transaction costs, accretion expense associated with asset retirement obligations, reimbursed employee costs, non-cash rent, and distributions from unconsolidated affiliate investments, less payments under onerous performance obligations, non-controlling interest, and income (loss) from unconsolidated affiliate investments. 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 entities 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,	
	2017	2016	2017	2016
Net income (loss)	$ 28.7	$ 17.5	$ 74.7	$ (542.2)
Interest expense, net of interest income	48.9	48.0	140.5	137.9
Depreciation and amortization	136.3	126.2	407.1	373.0
Impairments	1.8	—	8.8	566.3
(Income) loss from unconsolidated affiliates (1)	(4.4)	(1.1)	(5.0)	0.5
Distribution from unconsolidated affiliates (2)	4.0	4.7	11.4	19.6
(Gain) loss on disposition of assets	1.1	(3.0)	0.8	(2.9)
Gain on extinguishment of debt	—	—	(9.0)	—
Unit-based compensation	10.1	7.3	38.7	22.5
Income tax provision	0.5	2.6	0.7	1.3
(Gain) loss on non-cash derivatives	3.3	1.6	(3.8)	16.0
Payments under onerous performance obligation offset to other current and long-term liabilities	(4.5)	(4.5)	(13.5)	(13.5)
Other (3)	0.8	1.5	3.5	7.5
Adjusted EBITDA before non-controlling interest	$ 226.6	$ 200.8	$ 654.9	$ 586.0
Non-controlling interest share of adjusted EBITDA (4)	(9.8)	(3.3)	(20.8)	(6.1)
Adjusted EBITDA, net to EnLink Midstream Partners, LP	$ 216.8	$ 197.5	$ 634.1	$ 579.9

(1) Includes a loss of $3.4 million for the nine months ended September 30, 2017 from the sale of our HEP interests.

(2) Distributions for the three and nine months ended September 30, 2016 do not include $32.7 million of distributions received from HEP during the third quarter of 2016 attributable to the redemption of preferred units. The preferred units were issued to us by HEP during the second and third quarters of 2016 for contributions of $29.5 million and $3.2 million, respectively.

(3) Includes accretion expense associated with asset retirement obligations; reimbursed employee costs from Devon and LPC Crude Oil Marketing LLC (“LPC”); successful acquisition transaction costs, which we do not consider in determining adjusted EBITDA because operating cash flows are not used to fund such costs; and non-cash rent, which relates to lease incentives pro-rated over the lease term.

(4) Non-controlling interest share of adjusted EBITDA includes ENLC’s 16% share of adjusted EBITDA from EnLink Oklahoma T.O., NGP’s 49.9% share of adjusted EBITDA from the Delaware Basin JV, which was formed in August 2016, Marathon Petroleum’s 50% share of adjusted EBITDA from the Ascension JV, which began operations in April 2017, and other minor non-controlling interests.

Distributable Cash Flow

We define distributable cash flow as adjusted EBITDA (as defined above), net to the Partnership, less interest expense (excluding amortization of the EnLink Oklahoma T.O. acquisition installment payable discount), litigation settlement adjustment, adjustments for the redeemable non-controlling interest, interest rate swaps, current income taxes and other, 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 entities 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,	
	2017	2016	2017	2016
Net cash provided by operating activities	$ 200.8	$ 209.6	$ 533.0	$ 509.2
Interest expense, net (1)	41.5	34.5	118.9	98.7
Current income tax	0.7	2.6	0.9	1.6
Distributions from unconsolidated affiliate investment in excess of earnings (2)	(0.1)	4.1	7.3	18.9
Other (3)	(1.7)	1.0	4.0	6.3
Changes in operating assets and liabilities which (provided) used cash:				
Accounts receivable, accrued revenues, inventories and other	127.5	(0.2)	105.5	14.2
Accounts payable, accrued gas and crude oil purchases and other (4)	(142.1)	(50.8)	(114.7)	(62.9)
Adjusted EBITDA before non-controlling interest	$ 226.6	$ 200.8	$ 654.9	$ 586.0
Non-controlling interest share of adjusted EBITDA (5)	(9.8)	(3.3)	(20.8)	(6.1)
Adjusted EBITDA, net to EnLink Midstream Partners, LP	$ 216.8	$ 197.5	$ 634.1	$ 579.9
Interest expense, net of interest income	(48.9)	(48.0)	(140.5)	(137.9)
Amortization of EnLink Oklahoma T.O. installment payable discount included in interest expense (6)	6.4	13.3	19.9	39.0
Litigation settlement adjustment (7)	—	—	(18.1)	—
Non-cash adjustment for redeemable non-controlling interest	—	—	—	0.3
Interest Rate Swap (8)	—	0.4	—	0.4
Current taxes and other	(0.7)	(2.6)	(0.9)	(1.6)
Maintenance capital expenditures, net to EnLink Midstream Partners, LP (9)	(6.9)	(6.2)	(20.5)	(19.3)
Preferred unit accrued cash distributions (10)	(16.6)	—	(16.6)	—
Distributable cash flow	$ 150.1	$ 154.4	$ 457.4	$ 460.8

(1) Net of amortization of debt issuance costs, discount and premium, and valuation adjustment for redeemable non-controlling interest included in interest expense but not included in net cash provided by operating activities.

(2) Distributions for the three and nine months ended September 30, 2016 do not include $32.7 million of distributions received from HEP during the third quarter of 2016 attributable to the redemption of preferred units. The preferred units were issued to us by HEP during the second and third quarters of 2016 for contributions of $29.5 million and $3.2 million, respectively.

(3) Includes successful acquisition transaction costs, which we do not consider in determining adjusted EBITDA because operating cash flows are not used to fund such costs, non-cash rent, which relates to lease incentives pro-rated over the lease term, gains and losses on settled interest rate swaps designated as hedges related to debt issuances, which are recorded in other comprehensive income (loss), and reimbursed employee costs from Devon and LPC, which are costs reimbursed to us by previous employers pursuant to acquisition or merger.

(4) Net of payments under onerous performance obligation offset to other current and long-term liabilities.

(5) Non-controlling interest share of adjusted EBITDA includes ENLC's 16% share of adjusted EBITDA from EnLink Oklahoma T.O., NGP's 49.9% share of adjusted EBITDA from the Delaware Basin JV, which was formed in August 2016, Marathon Petroleum's 50% share of adjusted EBITDA from the Ascension JV, which began operations in April 2017, and other minor non-controlling interests.

(6) Amortization of the EnLink Oklahoma T.O. 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 EnLink Oklahoma T.O. assets.

(7) Represents recoveries from litigation settlement for amounts not previously deducted from distributable cash flow. See "Item 1. Financial Statements—Note 13" for additional information.

(8) During the third quarter of 2016, we entered into an interest rate swap arrangement that was not designated as a cash flow hedge to mitigate our exposure to interest rate movements prior to our note issuances. The gain on settlement of the interest rate swaps was considered excess proceeds for the note issuance and is therefore excluded from distributable cash flow.

(9) Excludes maintenance capital expenditures that were contributed by other entities and relate to the non-controlling interest share of our consolidated entities.

(10) Represents the cash distributions earned by the Series B Preferred Units of $15.9 million for the three and nine months ended September 30, 2017 and $0.7 million earned by the Series C Preferred Units for the three and nine months ended September 30, 2017, assuming a distribution is declared by our Board of Directors. Cash distributions to be paid to holders of the Series B Preferred Units and Series C Preferred Units are not available to common unitholders. See "Item 1. Financial Statements—Note 7" for additional information.

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 purchase and resell natural gas, NGLs, condensate and crude oil for a margin or to gather, process, transport or market natural gas, NGLs, condensate and crude oil for a fee. 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 (loss) to gross operating margin (in millions):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
Operating income (loss)	$ 73.4	$ 66.9	$ 201.4	$ (402.6)
Add (deduct):				
Operating expenses	102.1	98.0	308.8	296.3
General and administrative expenses	30.0	28.3	94.6	90.6
(Gain) loss on disposition of assets	1.1	(3.0)	0.8	(2.9)
Depreciation and amortization	136.3	126.2	407.1	373.0
Impairments	1.8	—	8.8	566.3
Gain on litigation settlement	—	—	(26.0)	—
Gross operating margin	$ 344.7	$ 316.4	$ 995.5	$ 920.7

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,	
	2017	2016	2017	2016
Texas Segment				
Revenues	$ 347.2	$ 280.2	$ 997.2	$ 767.4
Cost of sales	(198.5)	(134.1)	(554.7)	(329.0)
Total gross operating margin	$ 148.7	$ 146.1	$ 442.5	$ 438.4
Louisiana Segment				
Revenues	$ 738.5	$ 542.4	$ 2,021.0	$ 1,398.3
Cost of sales	(662.7)	(471.5)	(1,803.1)	(1,199.1)
Total gross operating margin	$ 75.8	$ 70.9	$ 217.9	$ 199.2
Oklahoma Segment				
Revenues	$ 244.4	$ 124.1	$ 583.1	$ 293.7
Cost of sales	(148.2)	(58.3)	(335.9)	(109.2)
Total gross operating margin	$ 96.2	$ 65.8	$ 247.2	$ 184.5
Crude and Condensate Segment				
Revenues	$ 308.6	$ 284.6	$ 973.1	$ 844.6
Cost of sales	(279.1)	(250.5)	(884.1)	(739.4)
Total gross operating margin	$ 29.5	$ 34.1	$ 89.0	$ 105.2
Corporate				
Revenues	$ (240.8)	$ (126.7)	$ (591.0)	$ (276.5)
Cost of sales	235.3	126.2	589.9	269.9
Total gross operating margin	$ (5.5)	$ (0.5)	$ (1.1)	$ (6.6)
Total				
Revenues	$ 1,397.9	$ 1,104.6	$ 3,983.4	$ 3,027.5
Cost of sales	(1,053.2)	(788.2)	(2,987.9)	(2,106.8)
Total gross operating margin	$ 344.7	$ 316.4	$ 995.5	$ 920.7
Midstream Volumes:				
Texas				
Gathering and Transportation (MMBtu/d)	2,251,700	2,579,500	2,265,900	2,657,600
Processing (MMBtu/d)	1,194,300	1,172,200	1,178,800	1,188,100
Louisiana				
Gathering and Transportation (MMBtu/d)	2,009,300	1,754,400	1,960,300	1,602,400
Processing (MMBtu/d)	443,400	487,900	452,500	496,400
NGL Fractionation (Gals/d)	5,814,800	5,259,400	5,630,600	5,194,700
Oklahoma				
Gathering and Transportation (MMBtu/d)	889,200	624,500	787,400	620,300
Processing (MMBtu/d)	872,200	570,100	753,500	571,800
Crude and Condensate				
Crude Oil Handling (Bbls/d)	95,700	72,800	104,500	98,300
Brine Disposal (Bbls/d)	4,800	3,700	4,700	3,500

Three Months Ended September 30, 2017 Compared to Three Months Ended September 30, 2016

Gross Operating Margin. Gross operating margin was $344.7 million for the three months ended September 30, 2017 compared to $316.4 million for the three months ended September 30, 2016, an increase of $28.3 million, or 8.9%, due to the following:

- *Texas Segment.* Gross operating margin in the Texas segment increased $2.6 million, which was primarily due to a $7.3 million increase from our Permian Basin processing assets as a result of higher volumes. This increase was partially offset by a $2.4 million decrease due to volume declines across our north Texas assets and a $2.0 million decrease due to the sale of the North Texas Pipeline (the “NTPL”) assets in December 2016.

- *Louisiana Segment.* Gross operating margin in the Louisiana segment increased $4.9 million, which was primarily due to a $3.2 million increase from our gas processing and transmission assets as a result of volume increases and a $1.8 million increase from our NGL business partially due to the start-up of our Ascension JV assets in April 2017.

- *Oklahoma Segment.* Gross operating margin in the Oklahoma segment increased $30.4 million, which was primarily due to higher volumes on our central Oklahoma assets.

- *Crude and Condensate Segment.* Gross operating margin in the Crude and Condensate segment decreased $4.6 million, which was primarily due to a $3.8 million decrease as a result of condensate stabilization volume declines and transportation rate decreases on our ORV assets, in addition to a $2.3 million decrease from volume declines for the Permian Basin trucking business. These decreases were partially offset by a $2.2 million increase due to the Greater Chickadee gathering system, which became fully operational in the first quarter of 2017.

- *Corporate Segment.* Gross operating margin in the Corporate segment decreased $5.0 million as a result of losses on derivative activity. For the three months ended September 30, 2017, there were unrealized losses of $3.3 million and realized losses of $2.2 million. For the three months ended September 30, 2016, there were unrealized losses of $1.6 million, partially offset by realized gains of $1.1 million.

Certain gathering and processing agreements in our Texas, Oklahoma and Crude and Condensate segments provide for a quarterly or annual minimum volume commitment (“MVC”). Under these agreements, our customers agree to ship and/or process a minimum volume of production 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 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 agreements with MVCs during periods of shortfall when it is known that the customer cannot, or will not, make up the deficiency in the subsequent period.

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, 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
September 30, 2016				
Midstream services	$ 0.4	$ 3.4	$ —	$ 3.8
Midstream services—related parties	7.7	4.4	5.2	17.3
Total	$ 8.1	$ 7.8	$ 5.2	$ 21.1

Operating Expenses. Operating expenses were $102.1 million for the three months ended September 30, 2017 compared to $98.0 million for the three months ended September 30, 2016, an increase of $4.1 million, or 4.2%. The primary contributors to the total increase by segment were as follows (dollars in millions):

	Three Months Ended September 30,		Change	
	2017	2016	$	%
Texas Segment	$ 41.1	$ 42.9	$ (1.8)	(4.2)%
Louisiana Segment	24.8	23.5	1.3	5.5 %
Oklahoma Segment	17.1	12.6	4.5	35.7 %
Crude and Condensate Segment	19.1	19.0	0.1	0.5 %
Total	$ 102.1	$ 98.0	$ 4.1	4.2 %

Operating expenses in the Oklahoma segment increased $4.5 million due to expanded operations, which resulted in increased labor and benefits charges and unit-based compensation expense due to increased headcount, as well as an increase in materials and supplies expense.

General and Administrative Expenses. General and administrative expenses were $30.0 million for the three months ended September 30, 2017 compared to $28.3 million for the three months ended September 30, 2016, an increase of $1.7 million, or 6.0%. The increase in general and administrative expenses was primarily due to $1.6 million of higher unit-based compensation expense associated with awards granted in 2017.

Depreciation and Amortization. Depreciation and amortization expenses were $136.3 million for the three months ended September 30, 2017 compared to $126.2 million for the three months ended September 30, 2016, an increase of $10.1 million, or 8.0%. Of this increase, $4.5 million was attributable to the expansion of our central Oklahoma assets; $4.3 million was attributable to the plant expansion of our Permian Basin processing assets; $1.2 million was attributable to the Greater Chickadee gathering system; and $0.7 million was attributable to the Ascension JV assets. These increases were partially offset by a $1.2 million decrease in depreciation expense attributable to the sale of NTPL in December 2016.

(Gain) Loss on Disposition of Assets. Loss on disposition of assets was $1.1 million for the three months ended September 30, 2017 compared to a gain of $3.0 million for the three months ended September 30, 2016, a decrease of $4.1 million. The gain on disposition of assets for the three months ended September 30, 2016 was primarily due to the retirement of certain plant assets and asset dispositions that resulted in the receipt of proceeds greater than the carrying values of the assets.

Interest Expense. Interest expense was $48.9 million for the three months ended September 30, 2017 compared to $48.0 million for the three months ended September 30, 2016, an increase of $0.9 million, or 1.9%. Interest expense consisted of the following (in millions):

	Three Months Ended September 30,	
	2017	2016
Senior notes	$ 40.0	$ 35.1
Credit Facility	2.5	2.2
Capitalized interest	(1.1)	(1.3)
Amortization of debt issue costs and net discounts	7.3	13.5
Cash settlements on interest rate swaps	—	(0.4)
Other	0.2	(1.1)
Total	$ 48.9	$ 48.0

Income (Loss) from Unconsolidated Affiliate Investments. Income from unconsolidated affiliate investments was $4.4 million for the three months ended September 30, 2017 compared to income of $1.1 million for the three months ended September 30, 2016, an increase of $3.3 million. This increase was primarily due to additional income from our GCF investment of $2.3 million for the three months ended September 30, 2017 as a result of higher fractionation revenues. In addition, for the three months ended September 30, 2016, income from unconsolidated affiliate investments included a loss of $1.1 million from our HEP investment, which was sold in March 2017.

Nine Months Ended September 30, 2017 Compared to Nine Months Ended September 30, 2016

Gross Operating Margin. Gross operating margin was $995.5 million for the nine months ended September 30, 2017 compared to $920.7 million for the nine months ended September 30, 2016, an increase of $74.8 million, or 8.1%, due to the following:

- *Texas Segment.* Gross operating margin in the Texas segment increased $4.1 million, which was primarily due to an $18.9 million increase from our Permian Basin processing assets as a result of higher volumes. This increase was offset by a $14.8 million decrease from our North Texas processing, gathering and transmission assets due to volume declines across our system, including a $9.7 million decrease due to the sale of the NTPL assets in December 2016.

- *Louisiana Segment.* Gross operating margin in the Louisiana segment increased $18.7 million, which was primarily due to a $10.0 million increase in our Louisiana gathering and transmission assets due to additional volumes, a $3.8 million increase from our NGL transmission and fractionation assets due to additional NGL volumes received from our Oklahoma and Permian assets, and a $4.5 million increase due to the start-up of our Ascension JV assets during 2017.

- *Oklahoma Segment.* Gross operating margin in the Oklahoma segment increased $62.7 million, which was primarily due to a $68.4 million increase from our central Oklahoma assets as a result of higher volumes. This increase was partially offset by a $5.1 million decrease from our Northridge gathering and processing assets due to price and volume reductions under a third-party contract.

- *Crude and Condensate Segment.* Gross operating margin in the Crude and Condensate segment decreased $16.2 million, which was primarily due to a $10.2 million decrease as a result of condensate stabilization volume declines and transportation rate decreases on our ORV assets, in addition to a $7.9 million decrease as a result of volume declines for our Midland Basin trucking business. These declines were partially offset by a $4.0 million increase due to the Greater Chickadee gathering system becoming fully operational in the first quarter of 2017.

- *Corporate Segment.* Gross operating margin in the Corporate segment increased $5.5 million as a result of derivative activity. For the nine months ended September 30, 2017, there were unrealized gains of $3.8 million, offset by realized losses of $4.9 million. For the nine months ended September 30, 2016, there were unrealized losses of $16.0 million, partially offset by realized gains of $9.4 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, 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
September 30, 2016				
Midstream services	$ 1.6	$ 7.9	$ —	$ 9.5
Midstream services—related parties	16.5	4.2	5.2	25.9
Total	$ 18.1	$ 12.1	$ 5.2	$ 35.4

Operating Expenses. Operating expenses were $308.8 million for the nine months ended September 30, 2017 compared to $296.3 million for the nine months ended September 30, 2016, an increase of $12.5 million, or 4.2%. The primary contributors to the increase by segment were as follows (dollars in millions):

	Nine Months Ended September 30,		Change	
	2017	2016	$	%
Texas Segment	$ 127.9	$ 125.2	$ 2.7	2.2 %
Louisiana Segment	74.8	72.2	2.6	3.6 %
Oklahoma Segment	45.9	37.2	8.7	23.4 %
Crude and Condensate Segment	60.2	61.7	(1.5)	(2.4)%
Total	$ 308.8	$ 296.3	$ 12.5	4.2 %

- *Texas Segment.* Operating expenses in the Texas segment increased $2.7 million primarily due to increased labor and benefits charges as a result of increased headcount and increased unit-based compensation expense, as well as increased operating costs from the Lobo II assets that went into service in the fourth quarter of 2016 as part of the Delaware Basin JV.

- *Louisiana Segment.* Operating expenses in the Louisiana segment increased $2.6 million primarily due to increased regulatory, utilities, and materials and supplies expenses as a result of the start-up of the Ascension JV.

- *Oklahoma Segment.* Operating expenses in the Oklahoma segment increased $8.7 million primarily due to increased labor and benefits charges attributable to higher headcount and increased materials and supplies expense as a result of expanded operations.

General and Administrative Expenses. General and administrative expenses were $94.6 million for the nine months ended September 30, 2017 compared to $90.6 million for the nine months ended September 30, 2016, an increase of $4.0 million, or 4.4%. The primary contributors to the increase were as follows:

- Unit-based compensation expense increased $10.8 million due to bonuses paid in the form of units that immediately vested in March 2017, as well as the accrual of annual bonuses for 2017.

- We incurred $3.8 million of transaction costs and $1.5 million of transition service fees related to the EnLink Oklahoma T.O. acquisition for the nine months ended September 30, 2016, with no transaction costs incurred for the nine months ended September 30, 2017.

- Salaries and wages expense decreased $1.9 million due to severance payments made during 2016.

Depreciation and Amortization. Depreciation and amortization expenses were $407.1 million for the nine months ended September 30, 2017 compared to $373.0 million for the nine months ended September 30, 2016, an increase of $34.1 million, or 9.1%. Of this increase, $18.0 million was attributable to the plant expansion of our Permian Basin processing assets; $10.9 million was attributable to the expansion of our central Oklahoma assets; $3.7 million was attributable to the Greater Chickadee gathering system; $3.4 million was attributable to the acceleration of depreciation for some north Texas compressor stations decommissioned during 2017; $1.8 million was attributable to the Ascension JV assets; and the remaining increase was attributable to other assets placed in service. These increases were partially offset by a $3.5 million decrease in depreciation expense related to the sale of NTPL in December 2016.

(Gain) Loss on Disposition of Assets. Loss on disposition of assets was $0.8 million for the nine months ended September 30, 2017 compared to a gain of $2.9 million for the nine months ended September 30, 2016, a decrease of $3.7 million. The gain on disposition for the nine months ended September 30, 2016 was due to the retirement of certain plant assets and asset dispositions that resulted in the receipt of proceeds greater than the carrying values of the assets.

Gain on Litigation Settlement. We recognized a gain on litigation settlement of $26.0 million for the nine months ended September 30, 2017. See "Item 1. Financial Statements—Note 13" for additional information.

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 the 2022 Notes. See "Item 1. Financial Statements—Note 6" for additional information.

Impairments. Impairment expense was $8.8 million for the nine months ended September 30, 2017 compared to $566.3 million for the nine months ended September 30, 2016, a decrease of $557.5 million. For the nine months ended September 30, 2017, we recognized impairments related to expired rights-of-way and an abandoned brine disposal well. For the nine months ended September 30, 2016, we recognized an impairment on goodwill of $566.3 million related to our Texas and Crude and Condensate segments.

Interest Expense. Interest expense was $140.5 million for the nine months ended September 30, 2017 compared to $137.9 million for the nine months ended September 30, 2016, an increase of $2.6 million, or 1.9%. Interest expense consisted of the following (in millions):

	Nine Months Ended September 30,	
	2017	2016
Senior notes	$ 115.0	$ 95.1
Credit facility	8.4	9.6
Capitalized interest	(5.1)	(5.5)
Amortization of debt issue costs and net discounts (premium)	21.6	39.5
Cash settlements on interest rate swap	—	(0.4)
Mandatory redeemable non-controlling interest	—	0.3
Other	0.6	(0.7)
Total	$ 140.5	$ 137.9

Income (Loss) from Unconsolidated Affiliate Investments. Income from unconsolidated affiliate investments was $5.0 million for the nine months ended September 30, 2017 compared to a loss of $0.5 million for the nine months ended September 30, 2016, an increase of $5.5 million. The increase was primarily due to additional income of $7.4 million from our GCF investment for the nine months ended September 30, 2017 as a result of higher fractionation revenues and lower operating expenses. Partially offsetting this increase, income from our HEP investment decreased $1.8 million due to a $1.6 million loss for the nine months ended September 30, 2016 and a $3.4 million loss on sale for the nine months ended September 30, 2017.

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, 2016, except as described below.

Impairment of Goodwill. Goodwill is the cost of an acquisition less the fair value of the net identifiable assets of the acquired business. We evaluate goodwill for impairment annually as of October 31 and whenever events or changes in circumstances indicate it is more likely than not that the fair value of a reporting unit is less than its carrying amount. We first assess qualitative factors to evaluate whether it is more likely than not that the fair value of a reporting unit is less than its carrying amount as the basis for determining whether it is necessary to perform a goodwill impairment test. We may elect to perform a goodwill impairment test without completing a qualitative assessment.

Prior to January 2017, if a goodwill impairment test was elected or required, we performed a two-step goodwill impairment test. The first step involved comparing the fair value of the reporting unit to its carrying amount. If the carrying amount of a reporting unit exceeded its fair value, the second step of the process involved comparing the implied fair value to the carrying value of the goodwill for that reporting unit. If the carrying value of the goodwill of a reporting unit exceeded the implied fair value of that goodwill, the excess of the carrying value over the implied fair value was recognized as an impairment loss.

In January 2017, the FASB issued ASU 2017-04, *Intangibles—Goodwill and Other (Topic 350)—Simplifying the Test for Goodwill Impairment* ("ASU 2017-04"). ASU 2017-04 simplifies the accounting for goodwill impairments by eliminating the requirement to compare the implied fair value of goodwill with its carrying amount as part of step two of the goodwill impairment test referenced in Accounting Standards Codification ("ASC") 350, *Intangibles—Goodwill and Other* ("ASC 350"). As a result, an entity should perform its annual or interim goodwill impairment test by comparing the fair value of a reporting unit with its carrying amount. An impairment charge should be recognized for the amount by which the carrying amount exceeds the reporting unit's fair value. However, the impairment loss recognized should not exceed the total amount of goodwill allocated to that reporting unit. ASU 2017-04 is effective for annual reporting periods beginning after December 15, 2019, including any interim impairment tests within those annual periods, with early application permitted for interim or annual goodwill impairment tests performed on testing dates after January 1, 2017. In January 2017, we elected to early adopt ASU 2017-04, and the adoption had no impact on our consolidated financial statements. We will perform future goodwill impairment tests according to ASU 2017-04.

Except for the items discussed above, the methodology and assumptions used to perform our goodwill assessments remains consistent with that described in Item 7 of our Annual Report on Form 10-K for the year ended December 31, 2016.

Liquidity and Capital Resources

Cash Flows from Operating Activities. Net cash provided by operating activities was $533.0 million for the nine months ended September 30, 2017 compared to $509.2 million for the nine months ended September 30, 2016. Operating cash flows and changes in working capital for comparative periods were as follows (in millions):

	Nine Months Ended September 30,	
	2017	2016
Operating cash flows before working capital	$ 537.3	$ 473.9
Changes in working capital	(4.3)	35.3

Operating cash flows before changes in working capital increased $63.4 million for the nine months ended September 30, 2017 compared to the nine months ended September 30, 2016 primarily due to a $69.3 million increase in gross operating margin, excluding gains and losses on derivative activity, and a $26.0 million gain on litigation settlement, partially offset by a $20.5 million increase in interest expense, excluding amortization of debt issue costs and net discounts, and a $15.4 million decrease in cash received on derivative settlements. The changes in working capital for the nine months ended September 30, 2017 compared to the nine months ended September 30, 2016 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 $475.3 million for the nine months ended September 30, 2017 and $1,181.4 million for the nine months ended September 30, 2016. Our primary investing cash flows were as follows (in millions):

	Nine Months Ended September 30,	
	2017	2016
Growth capital expenditures	$ (641.1)	$ (404.4)
Maintenance capital expenditures	(21.4)	(19.3)
Acquisition of business, net of cash acquired	—	(769.3)
Investment in unconsolidated affiliates	(11.8)	(45.0)
Proceeds from sale of unconsolidated affiliate investment	189.7	—
Distribution from unconsolidated affiliate investments in excess of earnings	7.3	51.6

Growth capital expenditures increased $236.7 million for the nine months ended September 30, 2017 compared to the nine months ended September 30, 2016. The increase was primarily due to capital expenditures related to the expansion of the central Oklahoma assets as well as expenditures for the Greater Chickadee crude oil gathering system in the Permian Basin and the Ascension JV assets in Louisiana.

Acquisition expenditures of $769.3 million for the nine months ended September 30, 2016 were for the EnLink Oklahoma T.O. acquisition.

Investment in unconsolidated affiliates decreased $33.2 million for the nine months ended September 30, 2017 compared to the nine months ended September 30, 2016. The decrease was primarily due to contributions of $45.0 million made to our HEP investment in 2016, including $32.7 million of contributions to HEP for preferred units. This decrease was partially offset by contributions to our Cedar Cove JV of $11.8 million in 2017.

Distributions from unconsolidated affiliates in excess of earnings decreased $44.3 million for the nine months ended September 30, 2017 compared to the nine months ended September 30, 2016. The decrease was primarily due to the redemption of our preferred units interest in our HEP investment for $32.7 million during the nine months ended September 30,

2016. The remaining difference was primarily due to decreased distributions following the sale of our HEP interest in March 2017.

In December 2016, we entered into an agreement to sell our ownership interest in HEP. We finalized the sale in March 2017 and received net proceeds of $189.7 million.

Cash Flows from Financing Activities. Net cash provided by financing activities was $72.4 million for the nine months ended September 30, 2017 and $726.3 million for the nine months ended September 30, 2016. Our primary financing activities consisted of the following (in millions):

	Nine Months Ended September 30,	
	2017	2016
Net repayments on Partnership credit facility	$ (120.0)	$ (339.2)
Unsecured senior notes borrowings, net of notes extinguished	331.6	499.3
Proceeds from issuance of common units	92.3	110.6
Proceeds from issuance of Series B Preferred Units	—	724.1
Proceeds from issuance of Series C Preferred Units	393.7	—
Contributions by non-controlling interests	105.5	179.4
Payment of installment payable for EnLink Oklahoma T.O. acquisition	(250.0)	—

On May 11, 2017, we issued $500.0 million in aggregate principal amount of our 5.450% senior unsecured notes due 2047 at a price to the public of 99.981% of their face value. Interest payments on the 2047 Notes are payable on June 1 and December 1 of each year, beginning December 1, 2017. 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 the 2022 Notes 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, 2017, we sold an aggregate of 5.3 million common units under the 2014 EDA and 2017 EDA, generating proceeds of $92.3 million. For the nine months ended September 30, 2016, we sold an aggregate of 6.7 million common units under the 2014 EDA, generating proceeds of $110.6 million.

In January 2016, we issued an aggregate of 50,000,000 Series B Preferred Units for net proceeds of $724.1 million. See “Item 1. Financial Statements—Note 7” for additional information.

In September 2017, we issued 400,000 Series C Preferred Units for net proceeds of $393.7 million. See “Item 1. Financial Statements—Note 7” for additional information.

For the nine months ended September 30, 2017, contributions by non-controlling interests included $59.3 million from ENLC to EnLink Oklahoma T.O., $43.9 million from NGP to the Delaware Basin JV and $2.3 million from Marathon Petroleum to the Ascension JV. For the nine months ended September 30, 2016, contributions by non-controlling interests included $137.7 million from NGP to the Delaware Basin JV, $27.9 million from ENLC to EnLink Oklahoma T.O. and $13.7 million from Marathon Petroleum to the Ascension JV.

For the nine months ended September 30, 2017, we paid $250.0 million for the second installment payable obligation related to the EnLink Oklahoma T.O. acquisition.

Distributions to unitholders, our general partner and our non-controlling interests also represent a primary use of cash in financing activities. Total cash distributions made for the nine months ended September 30, 2017 and 2016 were as follows (in millions):

	Nine Months Ended September 30,	
	2017	2016
Common units	$ 406.4	$ 387.0
General partner interest (including incentive distribution rights)	45.9	43.7
Distributions to non-controlling interests	17.0	5.6

Series B Preferred Unit distributions for 2016 and for the first two quarters for 2017 were paid in-kind in the form of additional Series B Preferred Units. As these were non-cash distributions, they were not reflected in our financing cash flows for the nine months ended September 30, 2017 and 2016. Beginning with the quarter ended September 30, 2017, Series B Preferred Unit distributions are payable in cash (the "Cash Distribution Component") at an amount per quarter equal to $0.28125 per Series B Preferred Unit 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.

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

If distributions are declared by the Board of Directors, cash distributions for the Series B Preferred Units and the Series C Preferred Units will decrease our cash flows from financing activities beginning in the fourth quarter of 2017.

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 2017 capital expenditures, including capital contributions to our unconsolidated affiliate investments, to be as follows (in millions):

	Remainder of 2017
Growth Capital Expenditures	
Texas segment	$ 15 - 40
Louisiana segment	10 - 20
Oklahoma segment (1)	50 - 110
Crude and Condensate segment	0 - 0
Corporate segment	0 - 0
Total growth capital expenditures	$ 75 - 170
Less: Growth capital expenditures funded by joint venture partners (2)	(10 - 26)
Growth capital expenditures, attributable to the Partnership	$ 65 - 144
Maintenance Capital Expenditures	$ 17 - 27

(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 EnLink Oklahoma T.O., contributions by NGP to the Delaware Basin JV and contributions by Marathon Petroleum to the Ascension JV.

Our primary capital projects for the remainder of 2017 and 2018 include the construction of our Chisholm III plant expansion and the development of additional gathering and compression assets in Oklahoma and the Permian Basin. See “Recent Developments” for further details.

We expect to fund growth capital expenditures from the proceeds of borrowings under our credit facility discussed below 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 2017 and 2018, it is possible that not all of the 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, 2017.

Total Contractual Cash Obligations. A summary of contractual cash obligations as of September 30, 2017 is as follows (in millions):

	Payments Due by Period						
	Total	Remainder 2017	2018	2019	2020	2021	Thereafter
Long-term debt obligations	$ 3,500.0	$ —	$ —	$ 400.0	$ —	$ —	$ 3,100.0
Credit facility	—	—	—	—	—	—	—
Interest payable on fixed long-term debt obligations	2,642.8	69.4	159.9	154.5	149.2	149.2	1,960.6
Capital lease obligations	4.9	0.4	1.5	1.5	1.5	—	—
Operating lease obligations	113.3	3.8	14.3	10.9	8.6	8.6	67.1
Purchase obligations	3.7	3.7	—	—	—	—	—
Delivery contract obligation	31.4	4.5	17.9	9.0	—	—	—
Pipeline capacity and deficiency agreements (1)	95.7	4.8	19.0	13.8	8.9	8.8	40.4
Inactive easement commitment (2)	10.0	—	—	—	—	—	10.0
Installment payable obligations (3)	250.0	—	250.0	—	—	—	—
Total contractual obligations	$ 6,651.8	$ 86.6	$ 462.6	$ 589.7	$ 168.2	$ 166.6	$ 5,178.1

(1) Consists of pipeline capacity payments for firm transportation and deficiency agreements.
(2) Amounts related to inactive easements paid as utilized by us with balance due in 2022 if not utilized.
(3) Amounts relate to the final installment payable for the acquisition of the EnLink Oklahoma T.O. assets with a balance due on January 7, 2018.

The above table does not include any physical or financial contract purchase commitments for natural gas 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.

In January 2017, we paid the $250.0 million installment payable obligation related to the EnLink Oklahoma T.O. acquisition, which was due on January 7, 2017. We funded this installment payment using various sources, including $84.6 million in proceeds received from the sale of NTPL, proceeds from equity issuances through the 2014 EDA and borrowings under our credit facility. Our contractual cash obligations for the remainder of 2017 and 2018 are expected to be funded from cash flows generated from our operations, with the exception of our $250.0 million installment payable obligation due January 7, 2018 related to the acquisition of the EnLink Oklahoma T.O. assets. We expect to fund payment of this installment obligation from the proceeds of borrowings under our credit facility, proceeds from the issuance of equity or both of these alternatives.

Indebtedness

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

Recent Accounting Pronouncements

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

Disclosure Regarding Forward-Looking Statements

This Quarterly Report on Form 10-Q includes forward-looking statements within the meaning of federal securities laws. Statements included in this report that are not historical facts are forward-looking statements. These statements can be identified by the use of forward-looking terminology including “forecast,” “may,” “believe,” “will,” “expect,” “anticipate,” “estimate,” “continue” or other similar words. These statements discuss future expectations, contain projections of results of operations or of financial condition or state other “forward-looking” information. 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 specific uncertainties discussed elsewhere in this Quarterly Report on Form 10-Q, the risk factors set forth in Part II, “Item 1A. Risk Factors” of this report and in our Annual Report on Form 10-K for the year ended December 31, 2016 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 U.S. Commodity Futures Trading Commission (“CFTC”) to regulate certain markets for derivative products, including over-the-counter (“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 significant risks due to fluctuations in commodity prices. Our exposure to these risks is primarily in the gas processing component of our business. We currently process gas under four main types of contractual arrangements as summarized below. Approximately 86% of our processing margins were from fixed-fee based contracts for the nine months ended September 30, 2017.

1. *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.

2. *Percent of liquids 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 percent of liquids contracts, but they do decline during periods of low liquids prices.

3. *Percent of proceeds contracts:* Under these contracts, we receive a fee as 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 percent of proceeds contracts, but they do decline during periods of low natural gas and liquids prices.

4. *Fixed-fee based contracts:* Under these contracts, we have no direct commodity price exposure and are paid a fixed fee per unit of volume that is processed.

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 and NGLs using over-the-counter derivative financial instruments with only certain well-capitalized counterparties that have been approved by our risk management committee.

We have hedged our exposure to fluctuations in prices for natural gas and NGL 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, 2017 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 OPIS. 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 2017 - September 2018	Ethane	341 (MBbls)	$0.2857/gal	Index	$ (0.1)
October 2017 - September 2018	Propane	537 (MBbls)	Index	$0.6583/gal	(4.0)
October 2017 - September 2018	Normal Butane	344 (MBbls)	Index	$0.7749/gal	1.3
October 2017 - September 2018	Natural Gasoline	79 (MBbls)	Index	$1.1270/gal	(0.3)
October 2017 - October 2018	Natural Gas	85,392 (MMBtu/d)	Index	$3.0561/MMBtu	0.7
December 2017	Condensate	90 (Mbbls)	Index	$50.90/bbl	(0.1)
					$ (2.5)

(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, 2017, 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 $2.5 million. The aggregate effect of a hypothetical 10% change, increase or decrease, in gas and NGL prices would result in a change of approximately $1.7 million in the net fair value of these contracts as of September 30, 2017.

Interest Rate Risk

We are exposed to interest rate risk on our variable rate credit facility. At September 30, 2017, we had no outstanding borrowings under this facility.

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 $3,564.7 million as of September 30, 2017, based on market prices of similar debt at September 30, 2017. 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 $291.7 million decrease in fair value of our senior unsecured notes at September 30, 2017.

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 EnLink Midstream GP, LLC, 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, 2017), 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

There has been no change in our internal control over financial reporting that occurred in the three months ended September 30, 2017 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.

For a discussion of certain litigation and similar proceedings, see “Item 1. Financial Statements—Note 13.”

Item 1A. Risk Factors

Information about risk factors does not differ materially from that set forth in Part I, Item 1A of our Annual Report on Form 10-K for the year ended December 31, 2016, except for the new risk factor set forth below.

Our business is subject to a number of weather-related risks. These weather conditions can cause significant damage and disruption to our operations and adversely impact our financial condition, results of operations or cash flows.

Virtually all of our operations are exposed to potential natural disasters, including hurricanes, tornadoes, storms, floods, fires and earthquakes. In particular, south Louisiana and the Gulf of Mexico experience hurricanes and other extreme weather conditions on a frequent basis. The location of our significant assets and concentration of activity in these regions make us particularly vulnerable to weather risks in these areas.

High winds, storm surge, flooding and other natural disasters can cause significant damage and curtail our operations for extended periods during and after such weather conditions, which may result in decreased revenues and otherwise adversely impact our financial condition, results of operations or cash flow. These interruptions could involve significant damage to people, property or the environment, and repair time and costs could be extensive. Any such event that interrupts the revenues generated by our operations, or which causes us to make significant expenditures not covered by insurance, could reduce our cash available for paying distributions to our partners and, accordingly, adversely affect our financial condition and the market price of our securities.

In addition, we rely on the volumes of natural gas, crude oil, condensate and NGLs gathered, processed, fractionated and transported on our assets. These volumes are influenced by the production from the regions that supply our systems. Adverse weather conditions can cause direct or indirect disruptions to the operations of, and otherwise negatively affect, producers, suppliers, customers and other third parties to which our assets are connected, even if our assets are not damaged. As a result, our financial condition, results of operations and cash flows could be adversely affected.

We may also suffer reputational damage as a result of a natural disaster or other similar event. The occurrence of such an event, or a series of such events, especially if one or more of them occurs in a highly populated or sensitive area, could negatively impact public perception of our operations and/or make it more difficult for us to obtain the approvals, permits, licenses or real property interests we need in order to operate our assets or complete planned growth projects.

Table of Contents

Item 6. Exhibits

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

Number		Description
3.1	—	Certificate of 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, 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	—	Certificate of Formation of EnLink Midstream GP, LLC (incorporated by reference to Exhibit 3.7 to our Registration Statement on Form S-1, file No. 333-97779).
3.7	—	Certificate of Amendment to the Certificate of Formation of EnLink Midstream GP, LLC (incorporated by reference to Exhibit 3.12 to our Registration Statement on Form S-3, file No. 333-194465).
3.8	—	Third Amended and Restated Limited Liability Company Agreement of EnLink Midstream GP, LLC, dated as of July 7, 2014 (incorporated by reference to Exhibit 3.2 to our Current Report on Form 8-K dated July 7, 2014, filed with the Commission on July 7, 2014, file No. 001-36340).
3.9	—	Amendment No. 1 to Third Amended and Restated Limited Liability Company Agreement of EnLink Midstream GP, LLC, dated as of January 7, 2016 (incorporated by reference to Exhibit 3.2 to our Current Report on Form 8-K dated January 12, 2016, filed with the Commission on January 12, 2016, 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, 2017, formatted in XBRL (eXtensible Business Reporting Language): (i) Consolidated Balance Sheets as of September 30, 2017 and December 31, 2016, (ii) Consolidated Statements of Operations for the three and nine months ended September 30, 2017 and 2016, (iii) Consolidated Statements of Changes in Partners’ Equity for the three and nine months ended September 30, 2017, (iv) Consolidated Statements of Cash Flows for the three and nine months ended September 30, 2017 and 2016, 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/ MICHAEL J. GARBERDING
Michael J. Garberding
President and Chief Financial Officer

November 1, 2017

Exhibit 31.1

CERTIFICATIONS

I, Barry E. Davis, certify that:

1. I have reviewed this quarterly report on Form 10-Q 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 1, 2017

/s/ BARRY E. DAVIS

BARRY E. DAVIS,
Chief Executive Officer
(principal executive officer)

Exhibit 31.2

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 1, 2017

/s/ MICHAEL J. GARBERDING

MICHAEL J. GARBERDING,
President and 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, 2017 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), each of the undersigned, Barry E. Davis, Chief Executive Officer of EnLink Midstream GP, LLC, and Michael J. Garberding, 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 1, 2017	/s/ BARRY E. DAVIS
	Barry E. Davis
	Chief Executive Officer
Date: November 1, 2017	/s/ MICHAEL J. GARBERDING
	Michael J. Garberding
	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.