EnLink Midstream, LLC
Form 10-Q
May 03, 2017
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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

Form 10-Q

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

For the quarterly period ended March 31, 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: 001-36336

ENLINK MIDSTREAM, LLC
(Exact name of registrant as specified in its charter)

Delaware	46-4108528
(State of organization)	(I.R.S. Employer Identification No.)

2501 CEDAR SPRINGS RD.	
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 ý 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 ý 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 ý 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 ý

As of April 27, 2017, the Registrant had 180,557,694 common units outstanding.

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

	March 31, 2017 (unaudited)	December 31, 2016
ASSETS		
Current assets:		
Cash and cash equivalents	$ 15.0	$ 11.7
Accounts receivable:		
Trade, net of allowance for bad debt of $0.1 and $0.1, respectively	47.1	63.9
Accrued revenue and other	358.1	369.6
Related party	107.1	100.2
Fair value of derivative assets	2.1	1.3
Natural gas and NGLs inventory, prepaid expenses and other	28.1	33.5
Investment in unconsolidated affiliates—current	—	193.1
Total current assets	557.5	773.3
Property and equipment, net of accumulated depreciation of $2,220.6 and $2,124.1, respectively	6,396.3	6,256.7
Fair value of derivative assets	0.1	—
Intangible assets, net of accumulated amortization of $201.1 and $171.6, respectively	1,594.7	1,624.2
Goodwill	1,542.2	1,542.2
Investment in unconsolidated affiliates—non-current	84.5	77.3
Other assets, net	2.2	2.2
Total assets	$ 10,177.5	$ 10,275.9
LIABILITIES AND MEMBERS' EQUITY		
Current liabilities:		
Accounts payable and drafts payable	$ 70.9	$ 69.2
Accounts payable to related party	12.5	10.4
Accrued gas, NGLs, condensate and crude oil purchases	306.2	333.3
Fair value of derivative liabilities	2.9	7.6
Installment payable, net of discount of $19.9 and $0.5, respectively	230.1	249.5
Other current liabilities	214.3	217.5
Total current liabilities	836.9	887.5
Long-term debt	3,521.1	3,295.3
Asset retirement obligations	13.7	13.5
Other long-term liabilities	42.1	42.5
Installment payable, net of discount of $26.3 at December 31, 2016	—	223.7
Deferred tax liability	544.5	542.6
Fair value of derivative liabilities	0.3	—
Redeemable non-controlling interest	4.8	5.2
Members' equity:		
Members' equity (180,551,299 and 180,049,316 units issued and outstanding at March 31, 2017 and December 31, 2016, respectively)	1,836.7	1,880.9
Non-controlling interest	3,377.4	3,384.7

Total members’ equity	5,214.1	5,265.6
Commitments and contingencies (Note 15)		
Total liabilities and members’ equity	$ 10,177.5	$ 10,275.9

See accompanying notes to consolidated financial statements.

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

	Three Months Ended March 31,	
	2017	2016
	(Unaudited)	
Revenues:		
Product sales	$990.0	$588.5
Product sales—related parties	42.7	24.5
Midstream services	127.4	114.5
Midstream services—related parties	159.0	162.6
Gain (loss) on derivative activity	2.8	(0.4)
Total revenues	1,321.9	889.7
Operating costs and expenses:		
Cost of sales (1)	1,002.3	586.2
Operating expenses (2)	104.1	98.2
General and administrative	36.1	35.1
(Gain) loss on disposition of assets	5.1	(0.2)
Depreciation and amortization	128.3	121.9
Impairments	7.0	873.3
Gain on litigation settlement	(17.5)	—
Total operating costs and expenses	1,265.4	1,714.5
Operating income (loss)	56.5	(824.8)
Other income (expense):		
Interest expense, net of interest income	(44.9)	(44.0)
Income (loss) from unconsolidated affiliates	0.7	(2.4)
Other income	—	0.1
Total other expense	(44.2)	(46.3)
Income (loss) before non-controlling interest and income taxes	12.3	(871.1)
Income tax provision	(3.0)	(0.2)
Net income (loss)	9.3	(871.3)
Net income (loss) attributable to the non-controlling interest	11.2	(413.7)
Net loss attributable to EnLink Midstream, LLC	$(1.9)	$(457.6)
Net loss attributable to EnLink Midstream, LLC per unit:		
Basic common unit	$(0.01)	$(2.56)
Diluted common unit	$(0.01)	$(2.56)

(1) Includes related party cost of sales of $28.7 million and $42.6 million for the three months ended March 31, 2017 and 2016, respectively.

(2) Includes related party operating expenses of $0.2 million and $0.1 million for the three months ended March 31, 2017 and 2016, respectively.

See accompanying notes to consolidated financial statements.

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ENLINK MIDSTREAM, LLC
Consolidated Statement of Changes in Members' Equity
Three Months Ended March 31, 2017
(In millions)

	Common Units		Non-Controlling Interest	Total	Redeemable Non-Controlling Interest (Temporary Equity)
	$	Units	$	$	$
	(Unaudited)				
Balance, December 31, 2016	$1,880.9	180.0	$ 3,384.7	$5,265.6	$ 5.2
Issuance of common units by ENLK	—	—	55.2	55.2	—
Conversion of restricted units for common units, net of units withheld for taxes	(4.3)	0.6	—	(4.3)	—
Non-controlling partner's impact of conversion of restricted units	—	—	(5.0)	(5.0)	—
Unit-based compensation	9.0	—	9.0	18.0	—
Change in equity due to issuance of units by ENLK	(0.6)	—	0.9	0.3	—
Non-controlling interest distributions	—	—	(100.7)	(100.7)	—
Non-controlling interest contribution	—	—	20.8	20.8	—
Distributions to members	(46.4)	—	—	(46.4)	—
Distributions to redeemable non-controlling interest	—	—	—	—	(0.4)
Contribution from Devon to ENLK	—	—	1.3	1.3	—
Net income (loss)	(1.9)	—	11.2	9.3	—
Balance, March 31, 2017	$1,836.7	180.6	$ 3,377.4	$5,214.1	$ 4.8

See accompanying notes to consolidated financial statements.

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

	Three Months Ended March 31,	
	2017	2016
	(Unaudited)	
Cash flows from operating activities:		
Net income (loss)	$9.3	$(871.3)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Impairments	7.0	873.3
Depreciation and amortization	128.3	121.9
(Gain) loss on disposition of assets	5.1	(0.2)
Non-cash unit-based compensation	19.4	8.0
(Gain) loss on derivatives recognized in net income (loss)	(2.8)	0.4
Cash settlements on derivatives	(2.9)	5.6
Amortization of debt issue costs	1.0	0.9
Amortization of net discount on notes	6.3	11.7
Redeemable non-controlling interest expense	—	0.2
(Income) loss from unconsolidated affiliates	(0.7)	2.4
Other	2.5	(0.7)
Changes in assets and liabilities, net of assets acquired and liabilities assumed:		
Accounts receivable, accrued revenue and other	21.5	32.0
Natural gas and NGLs inventory, prepaid expenses and other	2.4	22.4
Accounts payable, accrued gas and crude oil purchases and other accrued liabilities	(18.8)	(12.2)
Net cash provided by operating activities	177.6	194.4
Cash flows from investing activities, net of assets acquired and liabilities assumed:		
Additions to property and equipment	(256.3)	(135.4)
Acquisition of business, net of cash acquired	—	(796.8)
Proceeds from sale of unconsolidated affiliate investment	189.7	0.2
Proceeds from sale of property	0.5	—
Investment in unconsolidated affiliates	(6.0)	(7.1)
Distribution from unconsolidated affiliates in excess of earnings	2.8	6.2
Net cash used in investing activities	(69.3)	(932.9)
Cash flows from financing activities:		
Proceeds from borrowings	813.0	397.3
Payments on borrowings	(587.3)	(259.0)
Payment of installment payable for EnLink Oklahoma T.O. acquisition	(250.0)	—
Payments on capital lease obligations	(1.0)	(1.1)
Debt financing costs	(0.2)	(0.3)
Conversion of restricted units, net of units withheld for taxes	(4.3)	(1.1)
Conversion of ENLK restricted units, net of units withheld for taxes	(5.0)	(1.1)
Proceeds from issuance of ENLK common units	55.2	2.1
Distributions to non-controlling partners	(101.1)	(93.1)
Distribution to members	(46.4)	(46.3)
Contribution from Devon	1.3	1.4
Proceeds from issuance of ENLK Preferred Units	—	724.5
Contributions by non-controlling partners	20.8	3.0

Net cash provided by (used in) financing activities	(105.0)	726.3
Net increase (decrease) in cash and cash equivalents	3.3	(12.2)
Cash and cash equivalents, beginning of period	11.7	18.0
Cash and cash equivalents, end of period	$15.0	$5.8
Cash paid for interest	$15.9	$3.5
Cash paid (refund) for income taxes	$2.2	$(6.6)

See accompanying notes to consolidated financial statements.

ENLINK MIDSTREAM, LLC
Notes to Consolidated Financial Statements
March 31, 2017
(Unaudited)

(1) General

In this report, the terms "Company" or "Registrant" as well as the terms "ENLC," "our," "we," and "us," or like terms, are sometimes used as abbreviated references to EnLink Midstream, LLC and its consolidated subsidiaries. References in this report to "EnLink Midstream Partners, LP," the "Partnership," "ENLK" or like terms refer to EnLink Midstream Partners, LP itself or EnLink Midstream Partners, LP together with its consolidated subsidiaries, including EnLink Midstream Operating, LP 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, LLC is a Delaware limited liability company formed in October 2013. The Company's common units are traded on the New York Stock Exchange under the symbol "ENLC."

Our assets consist of equity interests in EnLink Midstream Partners, LP and EnLink Oklahoma T.O. ENLK is a publicly traded limited partnership engaged in the gathering, transmission, processing and marketing of natural gas and natural gas liquids ("NGLs"), condensate and crude oil, as well as providing crude oil, condensate and brine services to producers. EnLink Oklahoma T.O. is a partnership held by us and ENLK, and is engaged in the gathering and processing of natural gas. As of March 31, 2017, our interests in ENLK and EnLink Oklahoma T.O. consist of the following:

- 88,528,451 common units representing an aggregate 22.0% limited partner interest in ENLK;
- 100.0% ownership interest in EnLink Midstream Partners GP, LLC, the general partner of ENLK (the "General Partner"), which owns a 0.4% general partner interest and all of the incentive distribution rights in ENLK; and
- 16% limited partner interest in EnLink Oklahoma T.O.

(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, natural gas liquids ("NGLs"), crude oil and condensate. We connect the wells of producers in our market areas to our gathering systems, process natural gas to remove NGLs, fractionate NGLs into purity products and market those products for a fee, transport natural gas and ultimately provide natural gas to a variety of markets. We purchase natural gas from natural gas producers and other supply sources and sell that natural gas to utilities, industrial consumers, other marketers and pipelines. We operate processing plants that process gas transported to the plants by major interstate pipelines or from our own gathering systems mainly under a variety of fee-based arrangements. We 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 also have crude oil and condensate terminal facilities that provide access for crude oil and condensate producers to premium markets. Our gas gathering systems consist of networks of pipelines that collect natural gas from points near producing wells and transport it to larger pipelines for further transmission. Our transmission pipelines primarily 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. We also have transmission lines that transport NGLs from east Texas and from our south Louisiana processing plants to our fractionators in south Louisiana. Our crude oil and condensate gathering and transmission systems consist of trucking facilities, pipelines, rail and barge facilities that, in exchange for a fee, transport crude oil from a producer site to end users and other pipelines. Our processing plants remove NGLs and CO_2 from a natural gas stream, and our fractionators separate the NGLs into separate NGL products, including ethane, propane, iso-butane, normal butane and natural gasoline.

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(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 new 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 statement of operations for the three months ended March 31, 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 we expect to be entitled in exchange for transferring goods or services to a customer. ASC 606 will also require significantly expanded disclosures regarding the qualitative and quantitative information of our 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 plan to use the modified retrospective transition method and do not plan to early adopt ASC 606. 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 this standard will have a material impact on our consolidated financial statements. We continue to evaluate the impacts ASC 606 will have on our disclosures.

(d) Property, Plant & Equipment

Gain or Loss on Disposition. We recognize any gain or loss upon the disposition or retirement of property, plant and equipment in operating income in the consolidated statement of operations. For the three months ended March 31, 2017, we retired certain plant assets in the Permian Basin that were damaged by fire, which resulted in a loss on disposition of $5.1 million.

Impairment Review. We evaluate our property, plant 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 three months ended March 31, 2017, we recognized an impairment of $7.0 million, which related to the carrying values of right-of-ways that expired and a brine disposal well that will be abandoned.

(3) Acquisition

On January 7, 2016, ENLC and ENLK acquired a 16% and 84% 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. ENLK's 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 ("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 ENLC and ENLK paid and the fair value of the identified assets received and liabilities assumed at the acquisition date (in millions):

Consideration:	
Cash	$805.8
Issuance of common units	214.9
ENLK’s total installment payable, net of discount of $79.1 million assuming payments made on January 7, 2017 and 2018	420.9
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 $4.8 million of direct transaction costs, of which $4.3 million were recognized as expense for the three months ended March 31, 2016. These costs are included in general and administrative costs in the accompanying consolidated statements of operations.

For the period from January 7, 2016 to March 31, 2016, we recognized $27.3 million of revenues and $14.2 million of net loss 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 the Texas, Crude and Condensate, and Corporate reporting units in the amount of $873.3 million was recognized in the first quarter of 2016 and is included as an impairment loss in the consolidated statement of operations for the three months ended March 31, 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 other 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 interim assessment was required for the first quarter of 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 10 to 20 years.

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

	Gross Carrying Amount	Accumulated Amortization	Net Carrying Amount
Three Months Ended March 31, 2017			
Customer relationships, beginning of period	$1,795.8	$ (171.6)	$1,624.2
Amortization expense	—	(29.5)	(29.5)
Customer relationships, end of period	$1,795.8	$ (201.1)	$1,594.7

The weighted average amortization period is 13.7 years. Amortization expense was approximately $29.5 million and $27.5 million for the three months ended March 31, 2017 and 2016, respectively.

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

2017 (remaining)	$88.4
2018	117.9
2019	117.9
2020	117.9
2021	117.9
Thereafter	1,034.7
Total	$1,594.7

(5) Related Party Transactions

We engage in various transactions with Devon and other related parties. For the three months ended March 31, 2017 and 2016, Devon accounted for 14.9% and 21.0% of our revenues, respectively. We had an accounts receivable balance related to transactions with Devon of $106.9 million as of March 31, 2017 and $100.2 million as of December 31, 2016. Additionally, we had an accounts payable balance related to transactions with Devon of $11.8 million as of March 31, 2017 and $10.4 million as of 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 financial statements.

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

(6) Long-Term Debt

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

	March 31, 2017			December 31, 2016		
	Outstanding Principal	Premium (Discount)	Long-Term Debt	Outstanding Principal	Premium (Discount)	Long-Term Debt
ENLK credit facility due 2020 (1)	$330.0	$ —	$330.0	$120.0	$ —	$120.0
ENLC credit facility due 2019 (2)	43.5	—	43.5	27.8	—	27.8
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 (3)	162.5	15.2	177.7	162.5	16.0	178.5
4.40% Senior unsecured notes due 2024	550.0	2.4	552.4	550.0	2.5	552.5
4.15% Senior unsecured notes due 2025	750.0	(1.1)	748.9	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	(6.6)	443.4	450.0	(6.6)	443.4
Debt classified as long-term	$3,536.0	$ 8.9	$3,544.9	$3,310.3	$ 9.6	$3,319.9
Debt issuance cost (4)			(23.8)			(24.6)
Long-term debt, net of unamortized issuance cost			$3,521.1			$3,295.3

(1) Bears interest based on Prime and/or LIBOR plus an applicable margin. The effective interest rate was 3.0% and 2.3% at March 31, 2017 and December 31, 2016, respectively.
(2) Bears interest based on Prime and/or LIBOR plus an applicable margin. The effective interest rate was 3.1% and 3.4% at March 31, 2017 and December 31, 2016, respectively.
(3) On April 3, 2017, ENLK issued notice to redeem its 7.125% senior unsecured notes due 2022 (the "2022 notes"). The 2022 notes will be redeemed on June 1, 2017 at 103.6% of the principal amount, plus accrued unpaid interest, for aggregate cash consideration of $174.1 million.
(4) Net of amortization of $10.0 million and $9.0 million at March 31, 2017 and December 31, 2016, respectively.

ENLC Credit Facility

We have a $250.0 million revolving credit facility that matures on March 7, 2019 and includes a $125.0 million letter of credit subfacility (the "ENLC Credit Facility"). Our obligations under the ENLC Credit Facility are guaranteed by two of our wholly-owned subsidiaries and secured by first priority liens on (i) 88,528,451 ENLK common units and the 100% membership interest in the General Partner indirectly held by us, (ii) the 100% equity interest in each of our wholly-owned subsidiaries held by us and (iii) any additional equity interests subsequently pledged as collateral under the ENLC Credit Facility.

The ENLC Credit Facility contains certain financial, operational and legal covenants. The financial covenants are tested on a quarterly basis, based on the rolling four-quarter period that ends on the last day of each fiscal quarter, and include (i) maintaining a maximum consolidated leverage ratio (as defined in the ENLC Credit Facility, but generally computed as the ratio of consolidated funded indebtedness to consolidated earnings before interest, taxes, depreciation, amortization and certain other non-cash charges) of 4.00 to 1.00, provided that the maximum consolidated leverage ratio is 4.50 to 1.00 during an acquisition period (as defined in the ENLC Credit Facility) and (ii) maintaining a minimum consolidated interest coverage ratio (as defined in the ENLC Credit Facility, but generally computed as the ratio of consolidated earnings before interest, taxes, depreciation, amortization and certain other non-cash charges to consolidated interest charges) of 2.50 to 1.00 unless an investment grade event (as defined in the ENLC Credit Facility) occurs.

Borrowings under the ENLC Credit Facility bear interest at our option at the Eurodollar Rate (the LIBOR Rate) plus an applicable margin (ranging from 1.75% to 2.50%) or the Base Rate (the highest of the Federal Funds Rate plus 0.5%, the 30-day Eurodollar Rate plus 1.0% or the administrative agent's prime rate) plus an applicable margin (ranging from 0.75% to 1.50%). The applicable margins vary depending on our leverage ratio. Upon breach by us of certain covenants governing the ENLC Credit Facility, amounts outstanding under the ENLC Credit Facility, if any, may become due and payable immediately and the liens securing the ENLC Credit Facility could be foreclosed upon. At March 31, 2017, ENLC was in compliance and expects to be in compliance with the covenants in the ENLC Credit Facility for at least the next twelve months.

As of March 31, 2017, there were no outstanding letters of credit and $43.5 million in outstanding borrowings under the ENLC Credit Facility, leaving approximately $206.5 million available for future borrowing based on the borrowing capacity of $250.0 million.

ENLK Credit Facility

ENLK has a $1.5 billion unsecured revolving credit facility (the "ENLK Credit Facility"), which includes a $500.0 million letter of credit subfacility. Under the ENLK Credit Facility, ENLK is permitted to (1) subject to certain conditions and the receipt of additional commitments by one or more lenders, increase the aggregate commitments under the ENLK 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 the ENLK Credit Facility by one year on each occasion. The ENLK 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 the ENLK Credit Facility and includes projected EBITDA from certain capital expansion projects) of no more than 5.0 to 1.0. If ENLK consummates one or more acquisitions, in which the aggregate purchase price is $50.0 million or more, ENLK 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 the ENLK Credit Facility bear interest at ENLK's 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 ENLK's credit rating. If ENLK breaches certain covenants governing the ENLK Credit Facility, amounts outstanding under the ENLK Credit Facility, if any, may become due and payable immediately. At March 31, 2017, ENLK was in compliance and expects to be in compliance with the covenants in the ENLK Credit Facility for at least the next twelve months.

As of March 31, 2017, there were $9.1 million in outstanding letters of credit and $330.0 million in outstanding borrowings under the ENLK Credit Facility, leaving approximately $1.2 billion available for future borrowing based on the borrowing capacity of $1.5 billion.

All other material terms and conditions of the ENLK 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.

(7) Income Taxes

Income taxes included in the consolidated financial statements were as follows for the periods presented (in millions):

	Three Months Ended March 31,	
	2017	2016
ENLC income tax expense	$3.0	$0.2
Total income tax expense	$3.0	$0.2

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

	Three Months Ended March 31,	
	2017	2016
Tax expense (benefit) at statutory federal rate (35%)	$0.4	$(160.5)
State income taxes benefit, net of federal tax benefit	—	(14.9)
Income tax expense from partnership	0.5	1.0
Unit-based compensation (1)	2.3	—
Non-deductible expense related to asset impairment	—	173.9
Other	(0.2)	0.7
Total income tax expense	$3.0	$0.2

(1) Relates to tax deficiencies recorded on vested units, which are recognized on the income statement in accordance with the adoption of ASU 2016-09.

(8) Certain Provisions of the Partnership Agreement

(a) Issuance of Common Units

In November 2014, ENLK entered into an Equity Distribution Agreement (the “BMO 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 (collectively, the “Sales Agents”) to sell up to $350.0 million in aggregate gross sales of ENLK’s common units from time to time through an “at the market” equity offering program. ENLK 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. ENLK has no obligation to sell any of the common units under the BMO EDA and may at any time suspend solicitation and offers under the BMO EDA. For the three months ended March 31, 2017, ENLK sold an aggregate of approximately 3.0 million common units under the BMO EDA, generating proceeds of approximately $55.2 million (net of approximately $0.6 million of commissions). ENLK used the net proceeds for general partnership purposes. As of March 31, 2017, approximately $92.0 million of gross common unit issuances remain available under the BMO EDA.

(b) Distributions

Unless restricted by the terms of the ENLK Credit Facility and/or the indentures governing ENLK’s unsecured senior notes, ENLK must make distributions of 100% of available cash, as defined in the partnership agreement, within 45 days following the end of each quarter. Distributions are made to the General Partner in accordance with its current percentage interest with the remainder to the common unitholders, subject to the payment of incentive distributions as described below to the extent that certain target levels of cash distributions are achieved. The General Partner was not entitled to its general partner or incentive distributions with respect to the ENLK Class C Common Units issued in kind. In addition, the General Partner is not entitled to its general partner or incentive distributions with respect to ENLK’s Preferred Units until such units are converted to common units.

The General Partner owns the general partner interest in ENLK and all of its incentive distribution rights. The General Partner is entitled to receive incentive distributions if the amount ENLK distributes with respect to any quarter exceeds levels specified in its partnership agreement. Under the quarterly incentive distribution provisions, generally the General Partner is entitled to 13.0% of amounts ENLK distributes in excess of $0.25 per unit, 23.0% of the amounts ENLK distributes in excess of $0.3125 per unit and 48.0% of amounts ENLK distributes in excess of $0.375 per unit.

Distributions on the Preferred Units for the three months ended December 31, 2016, were paid-in kind through the issuance of 1,130,131 additional Preferred Units on February 13, 2017. A distribution on the Preferred Units was declared for the three months ended March 31, 2017, which will result in the issuance of 1,154,147 additional Preferred Units on May 12, 2017.

A summary of ENLK's distribution activity relating to the common units for the three months ended March 31, 2017 and 2016, respectively, 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
2016		
Fourth Quarter of 2015	$ 0.39	February 11, 2016
First Quarter of 2016	$ 0.39	May 12, 2016

(c) Allocation of ENLK Income

Net income is allocated to the General Partner in an amount equal to its incentive distribution rights as described in (b) above. The 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, the percentage interest of ENLK's net income adjusted for ENLC's unit-based compensation specifically allocated to our General Partner. The net income allocated to the General Partner is as follows (in millions):

	Three Months Ended March 31, 2017	
	2017	2016
Income allocation for incentive distributions	$14.7	$13.8
Unit-based compensation attributable to ENLC's restricted units	(8.8)	(4.0)
General Partner share of net income (loss)	—	(2.4)
General Partner interest in net income	$5.9	$7.4

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(9) 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 March 31,	
	2017	2016
EnLink Midstream, LLC interest in net loss	$(1.9)	$(457.6)
Distributed earnings allocated to:		
Common units (1)	$45.9	$45.6
Unvested restricted units (1)	0.6	0.5
Total distributed earnings	$46.5	$46.1
Undistributed loss allocated to:		
Common units	$(47.8)	$(498.5)
Unvested restricted units	(0.6)	(5.2)
Total undistributed loss	$(48.4)	$(503.7)
Net loss allocated to:		
Common units	$(1.9)	$(452.9)
Unvested restricted units	—	(4.7)
Total net loss	$(1.9)	$(457.6)
Basic and diluted net loss per unit:		
Basic	$(0.01)	$(2.56)
Diluted	$(0.01)	$(2.56)

(1) For the three months ended March 31, 2017 and 2016, represents a declared distribution of $0.255 per unit payable May 15, 2017 and a declared distribution of $0.255 per unit payable May 13, 2016, respectively.

A summary of our distribution activity relating to the ENLC common units for the three months ended March 31, 2017 and 2016, respectively, is provided below:

Declaration period	Distribution/unit	Date paid/payable
2017		
Fourth Quarter of 2016	$ 0.255	February 14, 2017
First Quarter of 2017	$ 0.255	May 15, 2017
2016		
Fourth Quarter of 2015	$ 0.255	February 12, 2016
First Quarter of 2016	$ 0.255	May 13, 2016

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

	Three Months Ended March 31, 2017	2016
Basic and diluted earnings per unit:		
Weighted average common units outstanding	180.2	178.7
Diluted weighted average units outstanding:		
Weighted average basic common units outstanding	180.2	178.7
Dilutive effect of restricted incentive units issued	—	—
Total weighted average diluted common units outstanding	180.2	178.7

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. All common unit equivalents were antidilutive for the three months ended March 31, 2017 and 2016 because a net loss existed for the corresponding periods.

(10) Asset Retirement Obligations

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

Three Months Ended March 31, 2017	
Balance, beginning of period	$13.5
Accretion expense	0.2
Balance, end of period	$13.7

Asset retirement obligations of $13.7 million and $13.5 million were included in “Asset retirement obligations” as non-current liabilities on the consolidated balance sheets as of March 31, 2017 and December 31, 2016, respectively.

(11) 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 March 31, 2017 and December 31, 2016;

- an approximate 30.0% ownership in Cedar Cove Midstream LLC (“Cedar Cove JV”) at March 31, 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;

- an approximate 31.0% common unit ownership interest in Howard Energy Partners (“HEP”) at December 31, 2016. In December 2016, we entered into an agreement to sell our ownership interest in HEP. We finalized the sale in the first quarter of 2017 and received net proceeds of $189.7 million.

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Notes to Consolidated Financial Statements (Continued)
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The following table shows the activity related to our investment in unconsolidated affiliates for the periods indicated (in millions):

	Gulf Coast Fractionators	Howard Energy Partners	Cedar Cove JV	Total
Three Months Ended				
March 31, 2017				
Contributions	$ —	$ —	$ 6.0	$6.0
Distributions	$ 2.7	$ —	$ 0.2	$2.9
Equity in income (loss) (1)	$ 4.0	$ (3.4)	$ 0.1	$0.7
March 31, 2016				
Contributions	$ —	$ 7.1	$ —	$7.1
Distributions	$ 3.0	$ 6.2	$ —	$9.2
Equity in loss	$ (1.7)	$ (0.7)	$ —	$(2.4)

(1) Includes a loss of $3.4 million for the three months ended March 31, 2017 from the sale of HEP in March 2017.

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

	March 31, 2017	December 31, 2016
Gulf Coast Fractionators	$ 49.8	$ 48.5
Howard Energy Partners	—	193.1
Cedar Cove JV	34.7	28.8
Total investment in unconsolidated affiliates	$ 84.5	$ 270.4

(12) Employee Incentive Plans

(a) Long-Term Incentive Plans

ENLC and ENLK each have similar unit-based compensation payment plans for officers and employees. ENLC grants unit-based awards under the EnLink Midstream, LLC 2014 Long-Term Incentive Plan (the “LLC Plan”), and ENLK grants unit-based awards under the amended and restated EnLink Midstream GP, LLC Long-Term Incentive Plan (the “GP Plan”).

We account for unit-based compensation in accordance with ASC 718, Stock Compensation (“ASC 718”), which requires that compensation related to all unit-based awards be recognized in the consolidated financial statements. Unit-based compensation cost is 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 ENLK since ENLC has no substantial or managed operating activities other than its interests in ENLK and EnLink Oklahoma T.O.

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

	Three Months Ended March 31, 2017	2016
Cost of unit-based compensation charged to general and administrative expense	$ 14.4	$ 6.3
Cost of unit-based compensation charged to operating expense	5.0	1.7
Total unit-based compensation expense	$ 19.4	$ 8.0
Interest of non-controlling partners in unit-based compensation	$ 7.3	$ 2.9
Amount of related income tax expense recognized in net income	$ 4.6	$ 1.9

(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 common units on such date. A summary of the restricted incentive unit activity for the three months ended March 31, 2017 is provided below:

	Three Months Ended March 31, 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)	822,865	18.46
Vested (1)(2)	(795,188)	25.84
Forfeited	(6,997)	16.87
Non-vested, end of period	2,045,500	$ 16.18
Aggregate intrinsic value, end of period (in millions)	$ 37.4	

(1) Restricted incentive units were issued in the first quarter of 2017 to officers and other employees. These restricted incentive units typically vest at the end of three years. In March 2017, ENLK issued 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 include 258,145 units withheld for payroll taxes paid on behalf of employees.

A summary of the restricted incentive units' aggregate intrinsic value (market value at vesting date) and fair value of units vested (market value at date of grant) for the three months ended March 31, 2017 and 2016, respectively, is provided below (in millions):

	Three Months Ended March 31,	
EnLink Midstream Partners, LP Restricted Incentive Units:	2017	2016
Aggregate intrinsic value of units vested	$15.3	$3.7
Fair value of units vested	$20.5	$9.0

As of March 31, 2017, there was $20.7 million of unrecognized compensation cost related to non-vested ENLK restricted incentive units for officers and employees. That cost is expected to be recognized over a weighted-average period of 2.0 years.

(c) EnLink Midstream Partners, LP Performance Units

For the three months ended March 31, 2017, the General Partner and our Managing Member 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 ENLC and ENLK (collectively, "EnLink"), on the grant date for the Subject Award. The performance units will vest based on the percentile ranking of the average of ENLC's and ENLK'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 ENLK's common units and the designated peer group securities; (iii) an estimated ranking of ENLK 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 values of performance units granted and the related assumptions:

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 %

The following table presents a summary of the performance units:

	Three Months Ended March 31, 2017	
EnLink Midstream Partners, LP Performance Units:	Number of Units	Weighted Average Grant-Date Fair Value
Non-vested, beginning of period	408,637	$ 11.53
Granted	176,648	25.73
Forfeited	—	—
Non-vested, end of period	585,285	$ 15.82
Aggregate intrinsic value, end of period (in millions)	$10.7	

As of March 31, 2017, there was $8.0 million of unrecognized compensation expense that related to non-vested ENLK performance units. That cost is expected to be recognized over a weighted-average period of 2.3 years.

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(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 date. A summary of the restricted incentive unit activity for the three months ended March 31, 2017 is provided below:

	Three Months Ended March 31, 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)	781,842	19.29
Vested (1)(2)	(726,692)	28.07
Forfeited	(6,706)	17.58
Non-vested, end of period	1,945,742	$ 16.67
Aggregate intrinsic value, end of period (in millions)	$ 37.7	

(1) Restricted incentive units were issued in the first quarter of 2017 to officers and other employees. These restricted incentive units typically vest at the end of three years. In March 2017, we issued 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 include 224,709 units withheld for payroll taxes paid on behalf of employees.

A summary of the restricted incentive units' aggregate intrinsic value (market value at vesting date) and fair value of units vested (market value at date of grant) for the three months ended March 31, 2017 and 2016, respectively, are provided below (in millions):

	Three Months Ended March 31,	
EnLink Midstream LLC Restricted Incentive Units:	2017	2016
Aggregate intrinsic value of units vested	$ 14.3	$ 3.8
Fair value of units vested	$ 20.4	$ 11.8

As of March 31, 2017, there was $20.2 million of unrecognized compensation costs related to non-vested ENLC restricted incentive units for directors, officers and employees. The cost is expected to be recognized over a weighted-average period of 2.0 years.

(e) EnLink Midstream, LLC's Performance Units

For the three months ended March 31, 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 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 values of performance units granted and the related assumptions:

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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:

	Three Months Ended March 31, 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)	$10.6	

As of March 31, 2017, there was $8.1 million of unrecognized compensation expense that related to non-vested ENLC performance units. That cost is expected to be recognized over a weighted-average period of 2.3 years.

(13) Derivatives

Commodity Swaps

We manage our exposure to changes in commodity prices by hedging the impact of market fluctuations. Swaps are used to manage and hedge price and location risk related to these market exposures. 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 transactions as cash flow or fair value hedges for hedge accounting treatment under ASC 815, Derivatives and Hedging. 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 in the consolidated statements of operations related to commodity swaps are (in millions):

	Three Months Ended March 31,	
	2017	2016
Change in fair value of derivatives	$5.3	$(6.0)
Realized gain (loss) on derivatives	(2.5)	5.6
Gain (loss) on derivative activity	$2.8	$(0.4)

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

	March 31, 2017	December 31, 2016
Fair value of derivative assets — current	$2.1	$ 1.3
Fair value of derivative assets — long-term	0.1	—
Fair value of derivative liabilities — current	(2.9)	(7.6)
Fair value of derivative liabilities — long-term	(0.3)	—
Net fair value of derivatives	$(1.0)	$ (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 are recorded at net as a gain (loss) on derivative activity in the consolidated statements of operations. We estimate the fair value of all of our derivative contracts using actively-quoted prices.

Set forth below is the summarized notional volumes and fair values of all instruments held for price risk management purposes and related physical offsets at March 31, 2017 (in millions). The remaining term of the contracts extend no later than October 2018.

		March 31, 2017		
Commodity	Instruments	Unit	Volume	Fair Value
NGL (short contracts)	Swaps	Gallons	(32.9)	$(0.3)
NGL (long contracts)	Swaps	Gallons	12.8	(0.2)
Natural Gas (short contracts)	Swaps	MMBtu	(15.4)	(0.3)
Natural Gas (long contracts)	Swaps	MMBtu	15.1	(0.4)
Condensate (short contracts)	Swaps	MMbbls	—	0.1
Condensate (long contracts)	Swaps	MMbbls	—	0.1
Total fair value of derivatives				$(1.0)

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 $2.2 million as of March 31, 2017 would be reduced to $0.4 million due to the offsetting of gross fair value payables against gross fair value receivables as allowed by the ISDAs.

(14) 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	
	March 31, 2017	December 31, 2016
Commodity Swaps (1)	$(1.0)	$ (6.3)
Total	$(1.0)	$ (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):

	March 31, 2017		December 31, 2016	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Long-term debt (1)	$3,521.1	$3,543.1	$3,295.8	$3,253.6
Installment Payables	$230.1	$232.9	$473.2	$476.6
Obligations under capital lease	$5.1	$4.3	$6.6	$6.1

(1) The carrying values of long-term debt are reduced by debt issuance costs of $23.8 million and $24.6 million at March 31, 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.

ENLK had $330.0 million and $120.0 million in outstanding borrowings under the ENLK Credit Facility as of March 31, 2017 and December 31, 2016, respectively. ENLC had $43.5 million and $27.8 million in outstanding borrowings under the ENLC Credit Facility as of March 31, 2017 and December 31, 2016, respectively. As borrowings under the credit facilities accrue interest under floating interest rate structures, the carrying value of such indebtedness approximates fair value for the amounts outstanding under the credit facilities. As of March 31, 2017 and December 31, 2016, ENLK had total borrowings under senior unsecured notes of $3.1 billion, maturing between 2019 and 2045 with fixed interest rates ranging from 2.7% to 7.1%. The fair values of all senior unsecured notes and installment payables as of March 31, 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.

(15) 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 EnLink Midstream Operating, LP. 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 the 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 the General Partner or its affiliates or interfering with a client or customer of the 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 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, and other environmental matters. The cost of planning, designing, constructing and operating pipelines, plants, and other facilities must incorporate compliance with environmental laws and regulations and safety standards. 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.

In the third quarter of 2016, in connection with the transition to our operational control of E2 Appalachian Compression, LLC and in preparation to commence operational control of E2 Ohio Compression, LLC, we discovered instances of noncompliance with air regulations and permits. This noncompliance was self-reported to the Ohio Environmental Protection Agency ("OEPA"), resulting in the issuance of notices of violations ("NOVs"). We have taken appropriate measures to achieve compliance with applicable requirements, and we are working with the OEPA on a settlement agreement for the NOVs, which we believe will not include any fines or penalties that would be material to our results of operations. 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 global settlement to resolve environmental noncompliance discovered or investigated during our assessment involving several of our Louisiana facilities and notices of potential violation and NOVs received from the LDEQ. We have taken appropriate measures to resolve all instances of noncompliance, and we continue to work with the LDEQ with respect to the proposed global settlement, which we believe will not include any fines or penalties that would be material to our results of operations. Lastly, we continue to work with Pipeline and Hazardous Materials Safety Administration regarding the notice of potential violation discussed in our Annual Report on Form 10-K for the fiscal 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.

At times, our subsidiaries acquire pipeline easements and other property rights by exercising rights of eminent domain and common carrier. As a result, from time to time we (or our subsidiaries) are a party to a number of lawsuits under which a court will determine the value of pipeline easements or other property interests obtained by our subsidiaries by condemnation. Damage awards in these suits should reflect the value of the property interest acquired and the diminution in the value of the remaining property owned by the landowner. However, some landowners have alleged unique damage theories to inflate their damage claims or assert valuation methodologies that could result in damage awards in excess of the amounts anticipated. Although it is not possible to predict the ultimate outcomes of these matters, we do not expect that awards in these matters will have a material adverse impact on our consolidated results of operations, financial condition or cash flows.

We (or our subsidiaries) are defending lawsuits filed by owners of property located near processing facilities or compression facilities constructed by us as part of our systems. The suits generally allege that the facilities create a private nuisance and have damaged the value of surrounding property. Claims of this nature have arisen as a result of the industrial development of natural gas gathering, processing and treating facilities in urban and occupied rural areas.

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 have 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 en banc. On April 12, 2017, the Court of Appeals denied the plaintiffs petition for rehearing. We intend to continue vigorously defending the case. The success of the plaintiffs' appeal as well as our costs and legal exposure, if any, related to the lawsuit are not currently determinable.

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. We are seeking to recover our losses from responsible parties. We sued Texas Brine Company, LLC ("Texas Brine"), 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. In August 2014, we received a partial settlement with respect to our claims in the amount of $6.1 million. In March 2017, we received an additional settlement payment of $17.5 million, which was recognized in "Gain on litigation settlement" in the consolidated statement of operations for the three months ended March 31, 2017. Additional claims remain outstanding. We also filed a claim with our insurers, which our insurers denied. We disputed the denial and sued our insurers. We cannot give assurance that we will be able to fully recover our losses through insurance recovery or claims against responsible parties.

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.

(16) Segment Information

Identification of the majority of our operating segments is based principally upon geographic regions served. Our reportable segments consist of the following: natural gas gathering, processing, transmission and fractionation operations located in north Texas and the Permian Basin in west Texas ("Texas"), the pipelines and processing plants located in Louisiana and NGL assets located in south 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 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 during the first quarter of 2017.

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

Summarized financial information for our reportable segments is shown in the following table (in millions):

	Texas	Louisiana	Oklahoma	Crude and Condensate	Corporate	Totals
Three Months Ended March 31, 2017						
Product sales	$85.1	$544.5	$14.5	$345.9	$—	$990.0
Product sales—related parties	106.5	10.2	64.4	0.8	(139.2)	42.7
Midstream services	27.8	53.1	27.9	18.6	—	127.4
Midstream services—related parties	105.1	29.0	49.4	3.3	(27.8)	159.0
Cost of sales	(179.2)	(564.7)	(88.7)	(336.7)	167.0	(1,002.3)
Operating expenses	(43.9)	(25.4)	(14.1)	(20.7)	—	(104.1)
Gain on derivative activity	—	—	—	—	2.8	2.8
Segment profit	$101.4	$46.7	$53.4	$11.2	$2.8	$215.5
Depreciation and amortization	$(49.8)	$(28.1)	$(36.5)	$(11.5)	$(2.4)	$(128.3)
Goodwill	$232.0	$—	$190.3	$—	$1,119.9	$1,542.2
Capital expenditures	$28.3	$32.7	$140.7	$37.4	$9.0	$248.1
Three Months Ended March 31, 2016						
Product sales	$62.5	$287.7	$7.8	$230.5	$—	$588.5
Product sales—related parties	37.3	7.4	10.6	0.2	(31.0)	24.5
Midstream services	27.4	55.2	15.1	16.8	—	114.5
Midstream services—related parties	110.3	12.7	45.0	5.2	(10.6)	162.6
Cost of sales	(91.3)	(302.1)	(19.3)	(215.1)	41.6	(586.2)
Operating expenses	(39.3)	(23.3)	(12.8)	(22.8)	—	(98.2)
Loss on derivative activity	—	—	—	—	(0.4)	(0.4)
Segment profit (loss)	$106.9	$37.6	$46.4	$14.8	$(0.4)	$205.3
Depreciation and amortization	$(46.2)	$(29.3)	$(33.8)	$(10.4)	$(2.2)	$(121.9)
Impairments	$(473.1)	$—	$—	$(93.2)	$(307.0)	$(873.3)
Goodwill	$230.4	$—	$190.3	$—	$1,119.9	$1,540.6
Capital expenditures	$23.3	$22.7	$69.2	$3.3	$1.9	$120.4

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

Segment Identifiable Assets:	March 31, 2017	December 31, 2016
Texas	$3,132.6	$3,142.6
Louisiana	2,312.7	2,349.3
Oklahoma	2,629.8	2,524.5
Crude and Condensate	861.9	836.8
Corporate	1,240.5	1,422.7
Total identifiable assets	$10,177.5	$10,275.9

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

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

	Three Months Ended March 31,	
	2017	2016
Segment profits	$215.5	$205.3
General and administrative expenses	(36.1)	(35.1)
Gain (loss) on disposition of assets	(5.1)	0.2
Depreciation and amortization	(128.3)	(121.9)
Impairments	(7.0)	(873.3)
Gain on litigation settlement	17.5	$—
Operating income (loss)	$56.5	$(824.8)

(17) Supplemental Cash Flow Information

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

	Three Months Ended March 31,	
	2017	2016
Non-cash financing activities:		
Non-cash issuance of ENLC common units (1)	$—	$214.9
Installment payable, net of discount of $79.1 million (2)	—	420.9

(1) Non-cash ENLC common units were issued as partial consideration for the acquisition of EnLink Oklahoma T.O. assets. See “Note 3—Acquisition” for further discussion.

(2) ENLK incurred installment purchase obligations, net of discount, payable to the seller in connection with the EnLink Oklahoma T.O. assets. ENLK 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.

(18) Other Information

The following table presents additional detail for other current liabilities, which consists of the following (in millions):

	March 31, 2017	December 31, 2016
Accrued interest	$ 58.4	$ 34.2
Accrued wages and benefits, including taxes	9.2	19.0
Accrued ad valorem taxes	13.0	23.5
Capital expenditure accruals	56.3	64.6
Onerous performance obligations	15.8	15.9
Other	61.6	60.3
Other current liabilities	$ 214.3	$ 217.5

(19) Subsequent Event

On April 3, 2017, ENLK issued notice to redeem its 2022 notes. The 2022 notes will be redeemed on June 1, 2017 at 103.6% of the principal amount, plus accrued unpaid interest, for aggregate cash consideration of $174.1 million, and we expect to recognize a gain on extinguishment of debt of approximately $3.2 million for the three months ending June 30, 2017.

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 terms "Company" or "Registrant" as well as the terms "ENLC," "our," "we," and "us," or like terms, are sometimes used as references to EnLink Midstream, LLC and its consolidated subsidiaries. References in this report to "EnLink Midstream Partners, LP," the "Partnership," "ENLK" or like terms refer to EnLink Midstream Partners, LP itself or EnLink Midstream Partners, LP together with its consolidated subsidiaries, including EnLink Midstream Operating, LP 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 liability company formed in October 2013. Our assets consist of equity interests in EnLink Midstream Partners, LP and EnLink Oklahoma T.O. EnLink Midstream Partners, LP is a publicly traded limited partnership engaged in the gathering, transmission, processing and marketing of natural gas and natural gas liquids ("NGLs"), condensate and crude oil, as well as providing crude oil, condensate and brine services to producers. EnLink Oklahoma T.O., a partnership owned by ENLK and ENLC, is engaged in the gathering and processing of natural gas. Our interests in EnLink Midstream Partners, LP and EnLink Oklahoma T.O. consisted of the following as of March 31, 2017:

- 88,528,451 common units representing an aggregate 22.0% limited partner interest in ENLK;

- 100.0% ownership interest in EnLink Midstream Partners GP, LLC, the general partner of ENLK (the "General Partner"), which owns a 0.4% general partner interest and all of the incentive distribution rights in ENLK; and

- 16% limited partner interest in EnLink Oklahoma T.O.

Each of ENLK and EnLink Oklahoma T.O. is required by its partnership agreement to distribute all its cash on hand at the end of each quarter, less reserves established by its general partner in its sole discretion to provide for the proper conduct of ENLK's or EnLink Oklahoma T.O.'s business, as applicable, or to provide for future distributions.

The incentive distribution rights in ENLK entitle us to receive an increasing percentage of cash distributed by ENLK as certain target distribution levels are reached. Specifically, they entitle us to receive 13.0% of all cash distributed in a quarter after each unit has received $0.25 for that quarter, 23.0% of all cash distributed after each unit has received $0.3125 for that quarter and 48.0% of all cash distributed after each unit has received $0.375 for that quarter.

Since we control the General Partner, we reflect our ownership interest in ENLK on a consolidated basis. Our consolidated results of operations are derived from the results of operations of ENLK and also include our deferred taxes, interest of non-controlling partners in ENLK's net income, interest income (expense) and general and administrative expenses specific to ENLC that are not reflected in ENLK's results of operations. Accordingly, the discussion of our financial position and results of operations in this "Management's Discussion and Analysis of Financial Condition and Results of Operations" primarily reflects the operating activities and results of operations of ENLK.
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 and transmission activities in north Texas and the Permian Basin in west Texas;

- Oklahoma Segment. The Oklahoma segment includes our natural gas gathering, processing and transmission activities in Cana-Woodford, Arkoma-Woodford, Northern Oklahoma Woodford, Sooner Trend Anadarko Basin Canadian and

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Kingfisher Counties (“STACK”), South Central Oklahoma Oil Province (“SCOOP”) and Central Northern Oklahoma Woodford (“CNOW”) 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 (“VEX”) located in the Eagle Ford Shale; and
- Corporate Segment. The Corporate segment includes our unconsolidated affiliate investments in the Cedar Cove JV in Oklahoma, our 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 during the first quarter of 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 94% of our gross operating margin was derived from fee-based services with no direct commodity exposure for the three months ended March 31, 2017. We reflect revenue as “Product sales” and “Midstream services” on the consolidated statements of operations.

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 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.

We typically gather or transport gas owned by others through our facilities for a fee. 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.

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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 March 31, 2017, the balance sheet reflects a liability of $40.4 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. The fees we earn on the product upgrade from this fractionation business are higher during periods with higher liquids prices.

We typically gather or transport crude oil and condensate owned by others by rail, truck, pipeline and barge facilities for a fee. 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 liquid 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 ENLK’s 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 in any reasonable manner determined by the General Partner in its sole discretion.

Recent Developments

Organic Growth

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.

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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 by 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 and 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 II Natural Gas Gathering and Processing Facility. 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. We are constructing an additional expansion of the Lobo II processing facility, which will provide an additional 60 MMcf/d of processing capacity by the end of the second quarter of 2017. Furthermore, we intend to construct an additional expansion, which will increase capacity by 30 MMcf/d and is expected to be completed by the fourth quarter of 2017. The Lobo facilities are part of our joint venture (the “Delaware Basin JV”) with an affiliate of NGP Natural Resources XI, LP (“NGP”).

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 three months ended March 31, 2017.

Issuance of ENLK Units

Equity Distribution Agreement. In November 2014, ENLK entered into an Equity Distribution Agreement (the “BMO EDA”) with BMO Capital Markets Corp. and certain other sales agents to sell up to $350.0 million in aggregate gross sales of ENLK’s common units from time to time through an “at the market” equity offering program. ENLK 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. ENLK has no obligation to sell any of the common units under the BMO EDA and may at any time suspend solicitation and offers under the BMO EDA.

For the three months ended March 31, 2017, ENLK sold an aggregate of 3.0 million common units under the BMO EDA, generating proceeds of $55.2 million (net of $0.6 million of commissions). ENLK used the net proceeds for general partnership purposes. As of March 31, 2017, approximately $92.0 million of gross common unit issuances remain available under the BMO EDA.

Non-GAAP Financial Measures

We include the following non-GAAP financial measures: Cash available for distribution and gross operating margin.

Cash Available for Distribution

We calculate cash available for distribution as distributions due to us from ENLK and our interest in EnLink Oklahoma T.O. adjusted EBITDA (as defined herein), less our share of maintenance capital attributable to our interest in EnLink Oklahoma T.O., our specific general and administrative costs as a separate public reporting entity, the interest costs associated with our debt and current taxes attributable to our earnings, plus our standalone impairment expense (if any). ENLC's share of EnLink Oklahoma T.O. growth capital expenditures are funded by borrowings under ENLC's credit facility and are not considered in determining ENLC's cash flow available for distribution. Cash available for distribution is a supplemental liquidity metric used by us and by external users of our financial statements, such as investors, commercial banks, research analysts and others to compare basic cash flows generated by us to the cash distributions we expect to pay our unitholders. Using this metric, management and external users of our financial statements can quickly compute the coverage ratio of

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estimated cash flows to planned cash distributions. Cash available for distribution is also an important financial measure for our unitholders since it serves as an indicator of our success in providing a cash return on investment.

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 and other gathering, well connections, compression and processing assets up to their original operating capacity, to maintain equipment reliability, integrity and safety and to address environmental laws and regulations.

The GAAP measure most directly comparable to cash available for distribution is net income (loss). Cash available for distribution should not be considered as an alternative to GAAP net income (loss). Cash available for distribution is not a presentation made in accordance with GAAP and has important limitations as an analytical tool. Investors should not consider cash available for distribution in isolation or as a substitute for analysis of our results as reported under GAAP. Because cash available for distribution excludes some items that affect net income (loss) and is defined differently by different companies in our industry, our definition of cash available for distribution may not be comparable to similarly-titled measures of other companies, thereby diminishing its utility.

The following is a calculation of the ENLC's cash available for distribution (in millions):

	Three Months Ended March 31,	
	2017	2016
Distribution declared by ENLK associated with (1):		
General partner interest	$0.6	$0.6
Incentive distribution rights	14.7	13.8
ENLK common units owned	34.5	34.5
Total share of ENLK distributions declared	$49.8	$48.9
Adjusted EBITDA of EnLink Oklahoma T.O. (2)	2.6	0.9
Transaction costs (3)	—	0.7
Total cash available	$52.4	$50.5
Uses of cash:		
General and administrative expenses	(1.0)	(1.8)
Interest expense	(0.4)	(0.3)
Total cash used	$(1.4)	$(2.1)
ENLC cash available for distribution	$51.0	$48.4

(1) Represents distributions to be paid to ENLC on May 12, 2017 and distributions paid on May 12, 2016.

(2) Represents ENLC's interest in EnLink Oklahoma T.O. adjusted EBITDA, which is disbursed to ENLC by EnLink Oklahoma T.O. on a monthly basis. EnLink Oklahoma T.O. adjusted EBITDA is defined as earnings before depreciation and amortization and provision for income taxes and includes allocated expenses from ENLK.

(3) Represents acquisition transaction costs attributable to ENLC's 16% interest in EnLink Oklahoma T.O, which are considered growth capital expenditures as part of the cost of the assets acquired.

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The following table provides a reconciliation of ENLC net income (loss) to ENLC cash available for distribution (in millions):

	Three Months Ended March 31,	
	2017	2016
Net income (loss) of ENLC	$9.3	$(871.3)
Less: Net income (loss) attributable to ENLK	18.1	(560.4)
Net loss of ENLC excluding ENLK	$(8.8)	$(310.9)
ENLC's share of distributions from ENLK (1)	49.8	48.9
ENLC's interest in EnLink Oklahoma T.O.'s non-cash expenses (2)	4.0	3.2
ENLC deferred income tax (benefit) expense (3)	2.5	(0.8)
ENLC corporate goodwill impairment	—	307.0
Non-controlling interest share of ENLK's net income (loss) (4)	3.4	0.2
Other items (5)	0.1	0.8
ENLC cash available for distribution	$51.0	$48.4

(1) Represents distributions declared by ENLK and to be paid to ENLC on May 12, 2017 and distributions paid by ENLK to ENLC on May 12, 2016.

(2) Includes depreciation and amortization and unit-based compensation expense allocated to EnLink Oklahoma T.O. for the three months ended March 31, 2017, and depreciation and amortization for the three months ended March 31, 2016.

(3) Represents ENLC’s stand-alone deferred taxes.

(4) Represents non-controlling interest share of ENLK’s net loss in the Delaware Basin JV and other minor non-controlling interests.

(5) Represents transaction costs attributable to ENLC’s share of the acquisition of EnLink Oklahoma T.O. for the three months ended March 31, 2016 and other non-cash items not included in cash available for distribution.

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.

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

	Three Months Ended March 31,	
	2017	2016
Operating income (loss)	$56.5	$(824.8)
Add (deduct):		
Operating expenses	104.1	98.2
General and administrative expenses	36.1	35.1
(Gain) loss on disposition of assets	5.1	(0.2)
Depreciation and amortization	128.3	121.9
Impairments	7.0	873.3
Gain on litigation settlement	(17.5)	—
Gross operating margin	$319.6	$303.5

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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 March 31, 2017	Three Months Ended March 31, 2016
Texas Segment		
Revenues	$324.5	$ 237.5
Cost of sales	(179.2)	(91.3)
Total gross operating margin	$145.3	$ 146.2
Louisiana Segment		
Revenues	$636.8	$ 363.0
Cost of sales	(564.7)	(302.1)
Total gross operating margin	$72.1	$ 60.9
Oklahoma Segment		
Revenues	$156.2	$ 78.5
Cost of sales	(88.7)	(19.3)
Total gross operating margin	$67.5	$ 59.2
Crude and Condensate Segment		
Revenues	$368.6	$ 252.7
Cost of sales	(336.7)	(215.1)
Total gross operating margin	$31.9	$ 37.6
Corporate		
Revenues	$(164.2)	$ (42.0)
Cost of sales	167.0	41.6
Total gross operating margin	$2.8	$ (0.4)
Total		
Revenues	$1,321.9	$ 889.7
Cost of sales	(1,002.3)	(586.2)
Total gross operating margin	$319.6	$ 303.5
Midstream Volumes:		
Texas		
Gathering and Transportation (MMBtu/d)	2,274,100	2,743,400
Processing (MMBtu/d)	1,162,100	1,198,100
Louisiana		
Gathering and Transportation (MMBtu/d)	1,931,300	1,475,000
Processing (MMBtu/d)	467,800	517,800
NGL Fractionation (Gals/d)	5,245,500	5,020,200
Oklahoma		
Gathering and Transportation (MMBtu/d)	705,500	617,000
Processing (MMBtu/d)	652,800	569,700
Crude and Condensate		
Crude Oil Handling (Bbls/d)	110,400	124,700
Brine Disposal (Bbls/d)	4,300	3,500

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Three Months Ended March 31, 2017 Compared to Three Months Ended March 31, 2016

Gross Operating Margin. Gross operating margin was $319.6 million for the three months ended March 31, 2017 compared to $303.5 million for the three months ended March 31, 2016, an increase of $16.1 million, or 5.3%, due to the following:

- Texas Segment. Gross operating margin in the Texas segment decreased $0.9 million, which was primarily attributable to a $7.2 million decrease in gross operating margin from our north Texas processing, gathering and transmission assets, which was substantially offset by a $6.2 million increase in gross operating margin attributable to volume increases in the Delaware and Midland Basin processing assets. The decrease in gross operating margin from our north Texas assets was primarily attributable to a $2.2 million decrease due to volume declines across our north Texas assets and a $5.0 million decrease attributable to the sale of the North Texas Pipeline (the “NTPL”) assets.

- Louisiana Segment. Gross operating margin in the Louisiana segment increased $11.2 million, which was primarily attributable to a $7.0 million increase in gross operating margin due to volume increases across our gathering and transmission assets. Additionally, our NGL business had an increase of $3.8 million due to higher NGL prices and higher volumes for the three months ended March 31, 2017 compared to the three months ended March 31, 2016.

- Oklahoma Segment. Gross operating margin in the Oklahoma segment increased $8.3 million, which was primarily driven by an $11.0 million increase in gross operating margin due to higher volumes at our central Oklahoma assets. This increase was partially offset by a $2.7 million decrease in gross operating margin at 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 $5.7 million, which was primarily attributable to a $4.0 million decrease due to volume declines in the Permian Basin trucking business, partially offset by a $0.4 million increase due to additional volumes on the Greater Chickadee gathering system, a $1.0 million decrease due to volume declines in the VEX pipeline and a $0.9 million decrease in brine disposal fees.

- Corporate Segment. Gross operating margin in the Corporate segment increased $3.2 million as a result of gains on derivative activity. For the three months ended March 31, 2017, there were unrealized gains of $5.3 million, partially offset by realized losses of $2.5 million. For the three months ended March 31, 2016, there were unrealized losses of $6.5 million, partially offset by realized gains of $6.1 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.

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

	Texas	Oklahoma	Crude and Condensate	Total
Three Months Ended				
March 31, 2017				
Midstream services	$0.3	$ 1.5	$ —	$1.8
Midstream services—related parties	12.5	3.6	0.8	16.9
Total	$12.8	$ 5.1	$ 0.8	$18.7
March 31, 2016				
Midstream services	$0.8	$ 1.1	$ —	$1.9
Midstream services—related parties	3.5	(0.2)	—	3.3
Total	$4.3	$ 0.9	$ —	$5.2

Operating Expenses. Operating expenses were $104.1 million for the three months ended March 31, 2017 compared to $98.2 million for the three months ended March 31, 2016, an increase of $5.9 million, or 6.0%. The primary contributors to the total increase by segment were as follows (dollars in millions):

	Three Months Ended March 31,		Change	
	2017	2016	$	%
Texas Segment	$43.9	$39.3	$4.6	11.7 %
Louisiana Segment	25.4	23.3	2.1	9.0 %
Oklahoma Segment	14.1	12.8	1.3	10.2 %
Crude and Condensate Segment	20.7	22.8	(2.1)	(9.2)%
Total	$104.1	$98.2	$5.9	6.0 %

- Texas Segment. Operating expenses in the Texas segment increased $4.6 million, which was primarily attributable to a $1.8 million increase in ad valorem taxes and a state sales and use tax refund received in March 2016, as well as an aggregate increase of $2.5 million attributable to an increase in labor and benefits charges due to a higher headcount and bonuses paid in the form of units that vested in March 2017, higher materials and supplies expense, and higher utility expenses.

- Louisiana Segment. Operating expenses in the Louisiana segment increased $2.1 million, which was primarily attributable to an increase in labor and benefits charges, including the cost of bonuses paid in the form of units that vested in March 2017, an increase in ad valorem taxes and an increase in materials and supplies expense.

- Oklahoma Segment. Operating expenses in the Oklahoma segment increased $1.3 million, which was primarily attributable to increased labor and benefits charges due to higher headcount and bonuses paid in the form of units that vested in March 2017, as well as increased materials and supplies expense.

- Crude and Condensate Segment. Operating expenses in the Crude and Condensate segment decreased $2.1 million, which was primarily attributable to a decrease in labor and benefits charges as a result of lower headcount as well as insurance proceeds received in 2017 that related to previously-recognized operating expenses.

General and Administrative Expenses. General and administrative expenses were $36.1 million for the three months ended March 31, 2017 compared to $35.1 million for the three months ended March 31, 2016, an increase of $1.0 million, or 2.8%. The primary contributors to the increase were as follows:

- Unit-based compensation expense increased $8.1 million due to bonuses paid in the form of units that immediately vested in March 2017;

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- We incurred $4.3 million of transaction costs and $1.1 million of transition service fees related to the EnLink Oklahoma T.O. acquisition for the three months ended March 31, 2016, with no transaction costs incurred for the three months ended March 31, 2017; and

- Bonus expense decreased by $1.9 million.

Depreciation and Amortization. Depreciation and amortization expenses were $128.3 million for the three months ended March 31, 2017 compared to $121.9 million for the three months ended March 31, 2016, an increase of $6.4 million, or 5.3%. Of the increase in depreciation and amortization expenses, $4.0 million was attributable to the acquisition of the EnLink Oklahoma T.O. assets; $2.0 million was attributable to the Lobo II assets held by the Delaware Basin JV; and $1.4 million was attributable to the Midland Energy Gathering Area 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 $5.1 million for the three months ended March 31, 2017 compared to a gain of $0.2 million for the three months ended March 31, 2016, a decrease of $5.3 million. For the three months ended March 31, 2017, we retired certain plant assets in the Permian Basin that were damaged by fire, which resulted in a loss on disposition of $5.1 million.

Impairments. Impairment expense was $7.0 million for the three months ended March 31, 2017 related to the carrying values of right-of-ways that expired and a brine disposal well that will be abandoned. For the three months ended March 31, 2016, we recognized an impairment on goodwill of $873.3 million, of which $566.3 million related to the Texas and Crude and Condensate segments, and $307.0 million related to the Corporate segment.

Gain on Litigation Settlement. We recognized a gain on litigation settlement of $17.5 million for the three months ended March 31, 2017. See “Item 1. Financial Statements—Note 15” for additional information.

Interest Expense. Interest expense was $44.9 million for the three months ended March 31, 2017 compared to $44.0 million for the three months ended March 31, 2016, an increase of $0.9 million, or 2.0%. Net interest expense consisted of the following (in millions):

	Three Months Ended March 31,	
	2017	2016
ENLK senior notes	$36.1	$30.0
ENLK credit facility	3.4	3.2
ENLC credit facility	0.4	0.2
Capitalized interest	(2.6)	(2.6)
Amortization of debt issue costs and net discounts	7.3	12.6
Mandatory redeemable non-controlling interest	—	0.2
Other	0.3	0.4
Total	$44.9	$44.0

Income (loss) from Unconsolidated Affiliate Investments. Income from unconsolidated affiliate investments was $0.7 million for the three months ended March 31, 2017 compared to a loss of $2.4 million for the three months ended March 31, 2016, an increase of $3.1 million. For the three months ended March 31, 2017, income from our investment in GCF increased $5.7 million due to increased revenue as a result of higher pipeline and fractionator feed volume, together with lower maintenance costs for 2017. This increase was partially offset by a loss of $3.4 million as a result of the sale of HEP during the three months ended March 31, 2017, primarily attributable to transaction fees associated with the sale. In addition, for the three months ended March 31, 2016, we incurred $0.7 million in losses from our investment in HEP.

Income Tax Provision. Income tax expense was $3.0 million for the three months ended March 31, 2017 compared to income tax expense of $0.2 million for the three months ended March 31, 2016, an increase of $2.8 million. The increase in income tax expense was primarily attributable to $2.3 million of tax deficiencies recognized on restricted incentive units that vested in March 2017 and an increase in taxable income between periods. See “Item 1. Financial Statements—Note 7” for further details.

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Net Income (loss) Attributable to Non-Controlling Interest. Net income attributable to non-controlling interest was $11.2 million for the three months ended March 31, 2017 compared to a net loss of $413.7 million for the three months ended March 31, 2016, an increase of $424.9 million. This increase was due primarily to impairments during the three months ended March 31, 2016. See Impairments above.

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.

Besides those 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 $177.6 million for the three months ended March 31, 2017 compared to $194.4 million for the three months ended March 31, 2016. Operating cash flows and changes in working capital for comparative periods were as follows (in millions):

Three Months
Ended March

	31,	
	2017	2016
Operating cash flows before working capital	$172.5	$152.2
Changes in working capital	5.1	42.2

Operating cash flows before changes in working capital increased $20.3 million for the three months ended March 31, 2017 compared to the three months ended March 31, 2016 primarily attributable to a gain on litigation settlement for the three months ended March 31, 2017 The changes in working capital for the three months ended March 31, 2017 compared to the three months ended March 31, 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.

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Cash Flows from Investing Activities. Net cash used in investing activities was $69.3 million for the three months ended March 31, 2017 and $932.9 million for the three months ended March 31, 2016. Our primary investing cash flows were as follows (in millions):

	Three Months Ended March 31,	
	2017	2016
Growth capital expenditures	$(252.1)	$(127.9)
Maintenance capital expenditures	(4.2)	(7.5)
Acquisition of business, net of cash acquired	—	(796.8)
Proceeds from sale of unconsolidated affiliate investment	189.7	0.2

Growth capital expenditures increased $124.2 million for the three months ended March 31, 2017 compared to the three months ended March 31, 2016. The increase was primarily due to capital expenditures related to the expansion in the Oklahoma segment for the EnLink Oklahoma T.O. assets, as well as expenditures for crude assets in the Permian Basin.

Maintenance capital expenditures decreased $3.3 million for the three months ended March 31, 2017 compared to the three months ended March 31, 2016. The decrease was due primarily to decreases in compressor overhauls and repairs in our Texas segment and other repairs in our Oklahoma and Louisiana segments.

Acquisition expenditures of $796.8 million for the three months ended March 31, 2016 were for the EnLink Oklahoma T.O. acquisition.

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

Cash Flows from Financing Activities. Net cash used in financing activities was $105.0 million for the three months ended March 31, 2017, and net cash provided by financing activities was $726.3 million for the three months ended March 31, 2016. Our primary financing activities consist of the following (in millions):

	Three Months Ended March 31,	
	2017	2016
Net borrowings on ENLK credit facility	$210.0	$129.0
Net borrowings on ENLC credit facility	15.7	9.3
Proceeds from issuance of ENLK common units	55.2	2.1
Proceeds from issuance of ENLK Preferred Units	—	724.5
Contributions by non-controlling interest	20.8	3.0
Payment of installment payable for EnLink Oklahoma T.O. acquisition	(250.0)	—

For the three months ended March 31, 2017, ENLK sold an aggregate of 3.0 million common units under the BMO EDA, generating proceeds of $55.2 million.

On April 3, 2017, ENLK issued notice to redeem its 7.125%senior unsecured notes due 2022 (the "2022 notes"). The 2022 notes will be redeemed on June 1, 2017 at 103.6% of the principal amount, plus accrued unpaid interest, for aggregate cash consideration of $174.1 million, and we expect to recognize a gain on extinguishment of debt of approximately $3.2 million for the three months ending June 30, 2017.

In January 2016, ENLK issued an aggregate of 50,000,000 Preferred Units representing ENLK's limited partner interests to Enfield Holdings, L.P. in a private placement for a cash purchase price of $15.00 per Preferred Unit, resulting in net proceeds of approximately $724.5 million after fees and deductions. Proceeds from the private placement were used to partially fund ENLK's portion of the purchase price payable in connection with the EnLink Oklahoma T.O. acquisition.

For the three months ended March 31, 2017, contributions by non-controlling interest included $17.1 million from NGP to the Delaware Basin JV and $3.7 million from Marathon Petroleum to the Ascension JV. For the three months ended March 31, 2016, contributions by non-controlling interest include $3.0 million from Marathon Petroleum to the Ascension JV.

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For the three months ended March 31, 2017, ENLK paid $250.0 million for the second installment payable obligation related to the EnLink Oklahoma T.O. acquisition.

Distributions to unitholders represent a primary use of cash in financing activities. Total cash distributions made during the three months ended March 31, 2017 and 2016 were as follows (in millions):

	Three Months Ended March 31,	
	2017	2016
Distributions to members	$46.4	$46.3
Distributions to non-controlling partners	101.1	93.1

Uncertainties. 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. We are seeking to recover our losses from responsible parties. We sued Texas Brine Company, LLC (“Texas Brine”), 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. In August 2014, we received a partial settlement with respect to our claims in the amount of $6.1 million. In March 2017, we received an additional settlement payment of $17.5 million, which was recognized in “Gain on litigation settlement” in the consolidated statement of operations for the three months ended March 31, 2017. Additional claims remain outstanding. We also filed a claim with our insurers, which our insurers denied. We disputed the denial and sued our insurers. We cannot give assurance that we will be able to fully recover our losses through insurance recovery or claims against responsible parties.

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	$84 - 114
Louisiana segment	56 - 70
Oklahoma segment (1)	218 - 320
Crude and Condensate segment	0 - 8

Corporate segment	8 - 14
Total growth capital expenditures	$366 - 526
Less: Growth capital expenditures funded by joint venture partners (2)	(29 - 39)
Growth capital expenditures, attributable to ENLC	$337 - 487
Maintenance Capital Expenditures	$34 - 44

(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 NGP to the Delaware Basin JV and contributions by Marathon Petroleum to the Ascension JV.

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Our primary capital projects for 2017 include the construction of our Chisholm III plant expansion, the development of additional gathering and compression assets in Oklahoma and the Midland Basin and contributions to the Delaware Basin JV, Cedar Cove JV and Ascension JV. See “Recent Developments” for further details.

We expect to fund the remaining growth capital expenditures from the proceeds of borrowings under the ENLK 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 remaining 2017 maintenance capital expenditures from operating cash flows. In 2017, 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 March 31, 2017.

Total Contractual Cash Obligations. A summary of contractual cash obligations as of March 31, 2017 is as follows (in millions):

	Payments Due by Period						
	Total	Remainder 2017	2018	2019	2020	2021	Thereafter
Long-term debt obligations	$3,162.5	$ —	$—	$400.0	$—	$—	$ 2,762.5
ENLK credit facility	330.0	—	—	—	330.0	—	—
ENLC credit facility	43.5	—	—	43.5	—	—	—
Interest payable on fixed long-term debt obligations	1,953.8	132.1	144.3	138.9	133.5	133.5	1,271.5
Capital lease obligations	5.8	1.2	1.5	1.5	1.6	—	—
Operating lease obligations	120.0	11.1	14.0	10.8	8.5	8.5	67.1
Purchase obligations	6.3	6.3	—	—	—	—	—
Delivery contract obligation	40.4	13.5	17.9	9.0	—	—	—
Pipeline capacity and deficiency agreements (1)	91.3	9.8	15.3	11.6	8.1	8.1	38.4
Inactive easement commitment (2)	10.0	—	—	—	—	—	10.0
Installment payable obligations (3)	250.0	—	250.0	—	—	—	—
Total contractual obligations	$6,013.6	$ 174.0	$443.0	$615.3	$481.7	$150.1	$ 4,149.5

(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 at end of 10 years if not utilized.
(3) Amounts relate to our partial consideration of 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 the ENLK 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. However, given the same borrowing amount and rates in effect March 31, 2017, the cash obligation for interest expense on the ENLK credit facility would be approximately $9.9 million per year or approximately $7.4 million for the remainder of 2017.

The interest payable under the ENLC 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. However, given the same borrowing amount and rates in effect at March 31, 2017, the cash obligation for interest expense on the ENLC credit facility would be approximately $1.3 million per year or approximately $1.0 million for the remainder of 2017.

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 payable using various sources, including $84.6 million in proceeds received from the sale of NTPL, proceeds from equity issuances through the BMO EDA and borrowings

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under the ENLK 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 ENLK's $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 the payment of the installment payable obligation from borrowings under the ENLK credit facility, proceeds from equity issuances through the BMO EDA, proceeds from the sale of certain assets or any combination 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," "anticipa "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 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 Commodities 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 and other rulemakings are pending at the CFTC, the product of which would be rules that implement mandates in new legislation to cause significant portions of derivatives markets to clear through clearinghouses. While some of these rules have been finalized, some have not and, as a result, the final form and timing of the implementation of the 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 position limit levels set the maximum amount of covered contracts that a trader may own or control separately or in combination, net long or short. The final rules also contained limited exemptions from position limits which would be phased in over time for certain bona fide hedging transactions and positions. The CFTC's original position limits rule was challenged in court by two industry associations and was vacated and remanded by a federal district court. 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 June 2016, the CFTC proposed certain refinements to the previously proposed 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 CFTC has withdrawn its appeal of the court order vacating the original position limits rule.

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

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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 85% of our processing margins are from fixed-fee based contracts for the three months ended March 31, 2017.

1. Processing margin contracts: Under this type of contract, 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.

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The following table sets forth certain information related to derivative instruments outstanding at March 31, 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 is 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)
April 2017 - March 2018	Ethane	305 (MBbls)	$0.2826/gal	Index	$ (0.2)
April 2017 - March 2018	Propane	548 (MBbls)	Index	$0.6120/gal	—
April 2017 - March 2018	Normal Butane	153 (MBbls)	Index	$0.7381/gal	(0.2)
April 2017 - March 2018	Natural Gasoline	82 (MBbls)	Index	$1.1105/gal	(0.1)
April 2017 - October 2018	Natural Gas	40,221 (MMBtu/d)	Index	$3.141/MMBtu	(0.7)
April 2017	Condensate	62 (MBbls)	Index	$51.57/bbl	0.2
					$ (1.0)

(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 March 31, 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 $1.0 million. The aggregate effect of a hypothetical 10% change, increase or decrease, in gas and NGL prices would result in a change of approximately $2.7 million in the net fair value of these contracts as of March 31, 2017.

Interest Rate Risk

ENLC is exposed to interest rate risk on our variable rate credit facility. At March 31, 2017, the credit facility had $43.5 million in outstanding borrowings under this facility. A 1% increase or decrease in interest rates would change its annual interest expense by approximately $0.4 million for the year.

ENLK is exposed to interest rate risk on its variable rate credit facility. At March 31, 2017, ENLK had $330.0 million in outstanding borrowings under this facility. A 1% increase or decrease in interest rates would change its annual interest expense by approximately $3.3 million for the year. ENLK is not exposed to changes in interest rates with respect to its senior unsecured notes due in 2019, 2022, 2024, 2025, 2026, 2044 or 2045 as these are fixed-rate obligations. The estimated fair value of ENLK's senior unsecured notes was approximately $3,169.6 million as of March 31, 2017, based on market prices of similar debt at March 31, 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 approximately a $226.3 million decrease in fair value of ENLK's senior unsecured notes at March 31, 2017.

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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 Manager, 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 (March 31, 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 March 31, 2017 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

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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 15.”

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 fiscal year ended December 31, 2016.

Item 6. Exhibits

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

Number	Description
3.1	Certificate of Formation of EnLink Midstream, LLC (incorporated by reference to Exhibit 3.1 to our Registration Statement on Form S-4, file No. 333-192419).
3.2	Certificate of Amendment to Certificate of Formation of EnLink Midstream, LLC (incorporated by reference to Exhibit 3.2 to our Registration Statement on Form S-4, file No. 333-192419).
3.3	First Amended and Restated Operating Agreement of EnLink Midstream, LLC, dated as of March 7, 2014 (incorporated by reference to Exhibit 3.1 to our Current Report on Form 8-K dated March 7, 2014, filed with the Commission on March 11, 2014, file No. 001-36336).
3.4	Certificate of Formation of EnLink Midstream Manager, LLC (incorporated by reference to Exhibit 3.12 to our Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2014).
3.5	Certificate of Amendment to the Certificate of Formation of EnLink Midstream Manager, LLC (incorporated by reference to Exhibit 3.13 to our Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2014).
3.6	First Amended and Restated Limited Liability Company Agreement of EnLink Midstream Manager, LLC (incorporated by reference to Exhibit 3.14 to our Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2014).
3.7	Certificate of Limited Partnership of EnLink Midstream Partners, LP (incorporated by reference to Exhibit 3.1 to EnLink Midstream Partners, LP’s Registration Statement on Form S-1, file No. 333-97779).
3.8	Certificate of Amendment to the Certificate of Limited Partnership of EnLink Midstream Partners, LP (incorporated by reference to Exhibit 3.2 to EnLink Midstream Partners, LP’s Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2012, file No. 000-50067).
3.9	Second Amendment to the Certificate of Limited Partnership of EnLink Midstream Partners, LP (incorporated by reference to Exhibit 3.3 to EnLink Midstream Partners, LP’s Current Report on Form 8-K dated March 6, 2014, filed with the Commission on March 11, 2014).
3.10	Eighth Amended and Restated Agreement of Limited Partnership of EnLink Midstream Partners, LP dated January 7, 2016 (incorporated by reference to Exhibit 3.1 to EnLink Midstream Partners, LP’s Current Report on Form 8-K dated January 12, 2016, filed with the Commission on January 12, 2016, file No. 001-36340).
3.11	Certificate of Formation of EnLink Midstream GP, LLC (incorporated by reference to Exhibit 3.7 to EnLink Midstream Partners, LP’s Registration Statement on Form S-1, file No. 333-97779).
3.12	Certificate of Amendment to the Certificate of Formation of EnLink Midstream GP, LLC (incorporated by reference to Exhibit 3.2 to EnLink Midstream Partners, LP’s Registration Statement on Form S-3, file No. 333-194465).
3.13	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 EnLink Midstream Partners, LP’s Current Report on Form 8-K dated July 7, 2014, filed with the Commission on July 7, 2014, file No. 001-36340).
3.14	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 EnLink Midstream Partners, LP’s Current Report on Form 8-K dated January 12, 2016, filed with the Commission on January 12, 2016, file No. 001-36340).
10.1 †	Form of Performance Unit Agreement made under the GP Plan (incorporated by reference to Exhibit 10.1 to EnLink Midstream Partners, LP’s Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2017)
10.2 †	Form of Performance Unit Agreement made under the LLC Plan (incorporated by reference to Exhibit 10.2 to EnLink Midstream Partners, LP’s Quarterly Report on Form 10-Q for the quarterly period ended March 31,

	2017)
10.3 †	Form of Restricted Incentive Unit Agreement made under the GP Plan (incorporated by reference to Exhibit 10.3 to EnLink Midstream Partners, LP’s Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2017)
10.4 †	Form of Restricted Incentive Unit Agreement made under the LLC Plan (incorporated by reference to Exhibit 10.4 to EnLink Midstream Partners, LP’s Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2017)
31.1 *	Certification of the Principal Executive Officer.
31.2 *	Certification of the Principal Financial Officer.
32.1 *	Certification of the Principal Executive Officer and Principal Financial Officer pursuant to 18 U.S.C. Section 1350.
101 *	The following financial information from EnLink Midstream, LLC's Quarterly Report on Form 10-Q for the quarter ended March 31, 2017, formatted in XBRL (eXtensible Business Reporting Language): (i) Consolidated Balance Sheets as of March 31, 2017 and December 31, 2016, (ii) Consolidated Statements of Operations for the three months ended March 31, 2017 and 2016, (iii) Consolidated Statements of Changes in Members’ Equity for the three months ended March 31, 2017, (iv) Consolidated Statements of Cash Flows for the three months ended March 31, 2017 and 2016, and (v) the notes to Consolidated Financial Statements.

* Filed herewith.

** Pursuant to Item 601(b)(2) of Regulation S-K, the Registrant agrees to furnish supplementally a copy of any omitted exhibit or schedule to the SEC upon request.

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

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SIGNATURES

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

EnLink Midstream, LLC

By: EnLink Midstream Manager, LLC,
its managing member

By: /s/ MICHAEL J. GARBERDING
Michael J. Garberding
President and Chief Financial Officer

May 3, 2017