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

Form 10-Q

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

for the quarterly period ended September 30, 2014

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: 000-50067

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

Delaware	**16-1616605**
(State of organization)	(I.R.S. Employer Identification No.)
2501 CEDAR SPRINGS **DALLAS, TEXAS**	**75201**
(Address of principal executive offices)	(Zip Code)

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

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

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

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

Large accelerated filer ☒	Accelerated filer ☐
Non-accelerated filer ☐ (Do not check if a smaller reporting company)	Smaller reporting company ☐

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

As of October 24, 2014, the Registrant had 233,042,749 common units outstanding.

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ENLINK MIDSTREAM PARTNERS, LP

Condensed Consolidated Balance Sheets

	September 30, 2014	December 31, 2013
	(Unaudited)	
	(In millions)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 24.1	$ —
Accounts receivable:		
Trade, net of allowance for bad debt	46.3	0.4
Accrued revenue and other	220.6	—
Related party	113.8	—
Fair value of derivative assets	1.1	—
Natural gas and natural gas liquids inventory, prepaid expenses and other	56.4	5.8
Assets held for disposition	—	72.7
Total current assets	462.3	78.9
Property and equipment, net of accumulated depreciation of $1,347.2 and $1,169.8, respectively	4,390.6	1,768.1
Fair value of derivative assets	0.2	—
Intangible assets, net of accumulated amortization of $23.2	501.8	—
Goodwill	2,257.8	401.7
Investments in unconsolidated affiliates	276.1	61.1
Other assets, net	28.8	—
Total assets	$ 7,917.6	$ 2,309.8
LIABILITIES AND PARTNERS' EQUITY		
Current liabilities:		
Accounts payable, drafts payable and other	$ 33.5	$ 1.7
Related party payables	4.2	—
Accrued gas and crude oil purchases	198.3	—
Fair value of derivative liabilities	0.9	—
Accrued capital expenditures	35.6	—
Contract liability	21.2	—
Other current liabilities	84.3	38.7
Accrued interest	30.9	—
Liabilities held for disposition	—	37.0
Total current liabilities	408.9	77.4
Long-term debt	1,746.7	—
Fair value of derivative liabilities	0.6	—
Asset retirement obligation	10.8	7.7
Other long-term liabilities	87.7	—
Deferred tax liability	72.7	440.9
Partners' equity	5,590.2	1,783.8
Total liabilities and partners' equity	$ 7,917.6	$ 2,309.8

See accompanying notes to condensed consolidated financial statements.

ENLINK MIDSTREAM PARTNERS, LP

Condensed Consolidated Statements of Operations

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
	(Unaudited) (In millions, except per unit amounts)			
Revenues:				
Revenues	$ 644.1	$ 46.8	$ 1,627.9	$ 136.1
Revenues - affiliates	206.3	531.4	872.0	1,557.0
Gain (loss) on derivative activity	1.0	—	(1.9)	—
Total revenues	851.4	578.2	2,498.0	1,693.1
Operating costs and expenses:				
Purchased gas, NGLs, condensate and crude oil (1)	597.2	435.5	1,798.0	1,279.6
Operating expenses (2)	75.8	35.8	193.3	116.0
General and administrative (3)	22.8	10.8	62.8	32.3
Depreciation and amortization	71.6	48.0	192.3	138.6
Gain on litigation settlement	(6.1)	—	(6.1)	—
Total operating costs and expenses	761.3	530.1	2,240.3	1,566.5
Operating income	90.1	48.1	257.7	126.6
Other income (expense):				
Interest expense, net of interest income	(12.7)	—	(30.5)	—
Income from equity investments	5.6	5.8	14.3	10.2
Gain on extinguishment of debt	2.4	—	3.2	—
Other income (expense)	0.2	—	(0.7)	—
Total other income (expense)	(4.5)	5.8	(13.7)	10.2
Income from continuing operations before non-controlling interest and income taxes	85.6	53.9	244.0	136.8
Income tax (provision) benefit	0.1	(19.3)	(20.7)	(49.2)
Net income from continuing operations	85.7	34.6	223.3	87.6
Discontinued operations:				
Income from discontinued operations, net of tax	—	(4.0)	1.0	6.3
Income from discontinued operations attributable to non-controlling interest, net of tax	—	0.3	—	1.4
Discontinued operations, net of tax	—	(4.3)	1.0	4.9
Net income	85.7	30.3	224.3	92.5
Net income attributable to the non-controlling interest	41.7	—	94.8	—
Net income attributable to EnLink Midstream Partners, LP	$ 44.0	$ 30.3	$ 129.5	$ 92.5
Predecessor interest in net income (4)	$ —	$ 30.3	$ 35.5	$ 92.5
General partner interest in net income	$ 3.5	$ —	$ 7.5	$ —
Limited partners' interest in net income attributable to EnLink Midstream Partners, LP	$ 40.5	$ —	$ 86.5	$ —
Net income attributable to EnLink Midstream Partners, LP per limited partners' unit:				
Basic per common unit	$ 0.18	$ —	$ 0.38	$ —
Diluted per common unit	$ 0.18	$ —	$ 0.38	$ —

(1) Includes $24.1 million and $397.8 million for the three months ended September 30, 2014 and 2013, respectively, and $349.9 million and $1,170.4 million for the nine months ended September 30, 2014 and 2013, respectively, of affiliate purchased gas, NGLs, condensate and crude oil.
(2) Includes $8.9 million for the three months ended September 30, 2013 and $5.9 million and $26.9 million for the nine months ended September 30, 2014 and 2013, respectively, of affiliate operating expenses.
(3) Includes $1.0 million and $10.8 million for the three months ended September 30, 2014 and 2013, respectively, and $10.6 million and $32.3 million for the nine months ended September 30, 2014 and 2013, respectively, of affiliate general and administrative expenses.
(4) Represents net income attributable to the Predecessor for the periods prior to March 7, 2014.

See accompanying notes to condensed consolidated financial statements.

ENLINK MIDSTREAM PARTNERS, LP

Consolidated Statement of Changes in Partners' Equity
Nine Months Ended September 30, 2014

	Common Units		General Partner Interest		Predecessor Equity	Non-Controlling Interest	
	$	Units	$	Units	$	$	Total
	(Unaudited) (In millions)						
Balance, December 31, 2013	$ —	—	$ —	—	$ 1,783.8	$ —	$ 1,783.8
Distributions to the Predecessor	—	—	—	—	(95.0)	—	(95.0)
Elimination of deferred taxes due to reorganization of predecessor	—	—	—	—	467.5	—	467.5
Issuance of units for reorganization of predecessor equity	1,095.9	120.5	—	—	(2,191.8)	1,095.9	—
Issuance of common units for acquisition of Partnership	3,329.6	109.1	48.7	1.6	—	—	3,378.3
Issuance of common units	71.9	2.4	—	—	—	—	71.9
Proceeds from exercise of unit options	0.4	0.1	—	—	—	—	0.4
Conversion of restricted units for common units, net of units withheld for taxes	(0.5)	—	—	—	—	—	(0.5)
Unit-based compensation	5.9	—	6.8	—	—	—	12.7
Distributions	(136.1)	—	(10.2)	—	—	—	(146.3)
Distributions to non-controlling interest	—	—	—	—	—	(106.9)	(106.9)
Net income	86.5	—	7.5	—	35.5	94.8	224.3
Balance, September 30, 2014	$ 4,453.6	232.1	$ 52.8	1.6	$ —	$ 1,083.8	$ 5,590.2

See accompanying notes to condensed consolidated financial statements.

ENLINK MIDSTREAM PARTNERS, LP

Consolidated Statements of Cash Flows

	Nine Months Ended September 30,	
	2014	2013
	(Unaudited) (In millions)	
Cash flows from operating activities:		
Net income from continuing operations	$ 223.3	$ 87.6
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	192.3	138.6
Accretion expense	0.4	0.3
Gain on extinguishment of debt	(3.2)	—
Deferred tax expense (benefit)	20.4	10.8
Non-cash stock-based compensation	12.7	—
Loss on derivatives recognized in net income	1.9	—
Cash paid on derivatives	(1.7)	—
Amortization of debt issue costs	0.6	—
Amortization of premium on notes	(1.7)	—
Distribution of earnings from equity investment	6.3	10.9
Income from equity investment	(14.3)	(10.2)
Changes in assets and liabilities:		
Accounts receivable, accrued revenue and other	42.4	—
Natural gas and natural gas liquids, prepaid expenses and other	(26.4)	(1.1)
Accounts payable, accrued gas and crude oil purchases and other accrued liabilities	(67.6)	8.1
Net cash provided by operating activities	385.4	245.0
Cash flows from investing activities:		
Additions to property and equipment	(472.1)	(201.3)
Acquisition of business	(35.2)	—
Deposit for acquisition	(23.5)	—
Investment in equity investment company	(5.7)	—
Distribution from equity investment company in excess of earnings	7.6	1.1
Net cash used in investing activities	(528.9)	(200.2)
Cash flows from financing activities:		
Proceeds from borrowings	1,974.0	—
Payments on borrowings	(1,586.7)	—
Payments on capital lease obligations	(2.1)	—
Decrease in drafts payable	(2.6)	—
Debt refinancing costs	(6.4)	—
Conversion of restricted units, net of units withheld for taxes	(0.5)	—
Proceeds from issuance of common units	71.9	—
Distribution to non-controlling partners	(106.9)	—
Proceeds from exercise of unit options	0.4	—
Distribution to partners	(146.3)	—
Distributions to Predecessor	(27.2)	(117.7)
Net cash provided by (used in) financing activities	167.6	(117.7)
Cash flow from discontinued operations:		
Net cash provided by operating activities	5.0	11.2
Net cash provided by (used in) investing activities	(0.6)	143.7
Net cash used in financing activities – net distributions to Devon and non-controlling interests	(4.4)	(97.6)
Net cash provided by discontinued operations	—	57.3
Net increase (decrease) in cash and cash equivalents	24.1	(15.6)
Cash and cash equivalents, beginning of period	—	15.6
Cash and cash equivalents, end of period	$ 24.1	$ —
Cash paid for interest	$ 18.3	$ —
Cash paid for income taxes	$ 7.1	$ —

See accompanying notes to condensed consolidated financial statements.

(1) General

In this report, the term "Partnership," as well as the terms "our," "we," "us" and "its," are sometimes used as abbreviated references to EnLink Midstream Partners, LP itself or EnLink Midstream Partners, LP together with its consolidated subsidiaries, including the Operating Partnership and Midstream Holdings and their consolidated subsidiaries. The term "Midstream Holdings" is sometimes used to refer to EnLink Midstream Holdings, LP itself or to EnLink Midstream Holdings, LP together with EnLink Midstream Holdings GP, LLC and their subsidiaries.

(a) Organization of Business

EnLink Midstream Partners, LP (formerly known as Crosstex Energy, L.P.) is a publicly traded Delaware limited partnership formed in 2002. Our common units are traded on the New York Stock Exchange under the symbol "ENLK." Our business activities are conducted through our subsidiary, EnLink Midstream Operating, LP (formerly known as Crosstex Energy Services, L.P.), a Delaware limited partnership (the "Operating Partnership"), and the subsidiaries of the Operating Partnership.

EnLink Midstream GP, LLC (formerly known as Crosstex Energy GP, LLC), a Delaware limited liability company, is our general partner (the "General Partner"). Our General Partner manages our operations and activities. Our General Partner is an indirect wholly-owned subsidiary of EnLink Midstream, LLC ("ENLC"). ENLC's units are traded on the New York Stock Exchange under the symbol "ENLC." Devon Energy Corporation ("Devon") owns ENLC's managing member and common units which represent approximately 70% of the outstanding limited liability company interests in ENLC.

Effective as of March 7, 2014, the Operating Partnership acquired (the "Acquisition") 50% of the outstanding equity interests in EnLink Midstream Holdings, LP ("Midstream Holdings") and all of the outstanding equity interests in EnLink Midstream Holdings GP, LLC, the general partner of Midstream Holdings, in exchange for the issuance by the Partnership of 120,542,441 units of limited partnership interests in the Partnership. At the same time, EnLink Midstream, Inc. (formerly known as Crosstex Energy, Inc.) ("EMI"), the entity that directly owns our General Partner, became a wholly-owned subsidiary of ENLC (together with the Acquisition, the "business combination"). Another wholly-owned subsidiary of ENLC owns the remaining 50% of the outstanding equity interests in Midstream Holdings. In this report, the term "Midstream Holdings" is sometimes used to refer to EnLink Midstream Holdings, LP itself or to EnLink Midstream Holdings, LP together with EnLink Midstream Holdings GP, LLC and their subsidiaries.

(b) Nature of Business

The Partnership primarily focuses on providing midstream energy services, including gathering, transmission, processing, fractionation and marketing, to producers of natural gas, natural gas liquids ("NGLs"), crude oil and condensate. We connect the wells of natural gas producers in our market areas to our gathering systems, process natural gas for the removal of 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 under a variety of fee-based arrangements. We provide a variety of crude oil and condensate services throughout the Ohio River Valley ("ORV"), which include crude oil and condensate gathering and transmission via pipelines, barges, rail and trucks and brine disposal. We also have crude oil and condensate terminal facilities in south Louisiana that provide access for crude oil and condensate producers to the premium markets in this area. 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 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 oil from a producer site to an end user. 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.

(2) Significant Accounting Policies

(a) ***Basis of Presentation***

The accompanying condensed 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 ("US 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.

Further, the unaudited consolidated financial statements give effect to the business combination and related transactions discussed above under the acquisition method of accounting and are treated as a reverse acquisition. Under the acquisition method of accounting, Midstream Holdings was the accounting acquirer in the transactions because its parent company, Devon, obtained control of the Partnership through the indirect control of the General Partner as a result of the business combination. Consequently, Midstream Holdings' assets and liabilities retained their carrying values and are reflected in the balance sheet as of December 31, 2013 as the Predecessor. All financial results prior to March 7, 2014 reflect the historical operations of Midstream Holdings and are reflected as Predecessor income on the statement of operations. Additionally, the Partnership's assets acquired and liabilities assumed by Midstream Holdings in the business combination were recorded at their fair values measured as of the acquisition date, March 7, 2014. The excess of the purchase price over the estimated fair values of the Partnership's net assets acquired was recorded as goodwill. Financial results subsequent to March 7, 2014 reflect the combined operations of Midstream Holdings and the Partnership, which give effect to new contracts entered into with Devon and include the legacy Partnership assets. Certain assets were not contributed to Midstream Holdings from the Predecessor and the operations of such non contributed assets have been presented as discontinued operations. In conjunction with the business combination, Midstream Holdings became a non-taxable entity which was treated as a reorganization under common control with the removal of historical deferred taxes reflected through equity.

(b) Management's Use of Estimates

The preparation of financial statements in accordance with US GAAP requires management of the Partnership to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the period. Actual results could differ from these estimates.

(c) Revenue Recognition

The Partnership recognizes revenue for sales or services at the time the natural gas, NGLs, condensate or crude oil are delivered or at the time the service is performed at a fixed or determinable price. The Partnership generally accrues one month of sales and the related gas, condensate and crude oil purchases and reverses these accruals when the sales and purchases are actually invoiced and recorded in the subsequent month. Actual results could differ from the accrual estimates. The Partnership's purchase and sale arrangements are generally reported in revenues and costs on a gross basis in the consolidated statement of operations in accordance with the Financial Accounting Standards Board Accounting Standards Codification ("FASB ASC") 605-45-45-1. Except for fee based arrangements, the Partnership acts as the principal in these purchase and sale transactions, has the risk and reward of ownership as evidenced by title transfer, schedules the transportation and assumes credit risk.

The Partnership accounts for taxes collected from customers attributable to revenue transactions and remitted to government authorities on a net basis (excluded from revenues).

(d) Gas Imbalance Accounting

Quantities of natural gas and NGLs over-delivered or under-delivered related to imbalance agreements are recorded monthly as receivables or payables using weighted average prices at the time of the imbalance. These imbalances are typically settled with deliveries of natural gas or NGLs. The Partnership had imbalance payables of $1.1 million at

September 30, 2014 which approximate the fair value of these imbalances. The Partnership had imbalance receivables of $1.3 million at September 30, 2014, which are carried at the lower of cost or market value. There were no imbalance payables or receivables at December 31, 2013.

(e) Cash and Cash Equivalents

The Partnership considers all highly liquid investments with an original maturity of three months or less to be cash equivalents.

(f) Natural Gas, Natural Gas Liquids, Crude Oil and Condensate Inventory

The Partnership's inventories of products consist of natural gas, NGLs, crude oil and condensate. The Partnership reports these assets at the lower of cost or market value which is determined by using the first-in, first-out method.

(g) Property, Plant, and Equipment

Property, plant and equipment are stated at historical cost less accumulated depreciation. Assets acquired in a business combination are recorded at fair value, including the Partnership's assets acquired by the Predecessor in the business combination. Repairs and maintenance are charged against income when incurred. Renewals and betterments, which extend the useful life of the properties, are capitalized. Subsequent to the business combination, interest costs for material projects are capitalized to property, plant and equipment during the period the assets are undergoing preparation for intended use.

Change in Depreciation Method. Historically, Midstream Holdings depreciated certain property, plant, and equipment using the units-of-production method. As a result of the business combination, the Partnership is operated as an independent midstream company and thus no longer has access to Devon’s proprietary reserve and production data historically used to compute depreciation under the units-of-production method. Additionally, the existing contracts with Devon were revised to a fee-based arrangement with minimum volume commitments. Effective March 7, 2014, the Partnership changed its method of computing depreciation for these assets to the straight-line method, consistent with the depreciation method applied to the Partnership’s acquired assets. In accordance with FASB ASC 250, the Partnership determined that the change in depreciation method is a change in accounting estimate effected by a change in accounting principle, and accordingly, the straight-line method will be applied on a prospective basis. This change is considered preferable because the straight-line method will more accurately reflect the pattern of usage and the expected benefits of such assets. The effect of this change in estimate resulted in a decrease in depreciation expense for the three and nine months ended September 30, 2014 by approximately $9.3 million and $21.0 million, or $0.04 and $0.09 per unit, respectively.

Gain or Loss on Disposition. Upon the disposition or retirement of property, plant and equipment related to continuing operations, any gain or loss is recognized in operating income in the statement of operations. When a disposition or retirement occurs which qualifies as discontinued operations, any gain or loss is recognized as income or loss from discontinued operations in the statement of operations.

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. The fair values of long-lived assets are generally determined from estimated discounted future net cash flows. Our estimate of cash flows is based on assumptions which include (1) the amount of fee based services and the purchase and resale margins on natural gas, together with volume of gas, NGL, condensate and crude oil available to the asset, (2) markets available to the asset, (3) operating expenses, and (4) future natural gas prices, crude prices, condensate prices and NGL product prices. The volume of available gas, condensate, NGLs and crude oil to an asset is sometimes based on assumptions regarding future drilling activity, which may be dependent in part on natural gas, NGL, condensate and crude oil prices. Projections of gas volumes and future commodity prices are inherently subjective and contingent upon a number of variable factors. Any significant variance in any of the above assumptions or factors could materially affect our cash flows, which could require us to record an impairment of an asset.

(h) Equity Method of Accounting

The Partnership accounts for investments it does not control but over which the Partnership has the ability to exercise significant influence using the equity method of accounting. Under this method, equity investments are initially carried at the acquisition cost, increased by the Partnership's proportionate share of the investee's net income and by contributions made, and decreased by the Predecessor's proportionate share of the investee's net losses and by distributions received.

The Partnership evaluates its equity investments for potential impairment whenever events or changes in circumstances indicate that the carrying amount of the investments may not be recoverable.

(i) Goodwill

Goodwill is the cost of an acquisition less the fair value of the net identifiable assets of the acquired business. The Partnership will evaluate goodwill for impairment annually as of October 31st, 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. The Partnership first assesses 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 the two-step goodwill impairment test. The Partnership may elect to perform the two-step goodwill impairment test without completing a qualitative assessment. If a two-step process goodwill impairment test is elected or required, the first step involves comparing the fair value of the reporting unit to which goodwill has been allocated with its carrying amount. If the carrying amount of a reporting unit exceeds its fair value, the second step of the process involves 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 exceeds the implied fair value of that goodwill, the excess of the carrying value over the implied fair value is recognized as an impairment loss.

The Partnership has approximately $2.3 billion of goodwill at September 30, 2014 primarily related to the legacy Partnership operations as a result of the March 7, 2014 business combination.

(j) Intangible Assets

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

The following table represents the Partnership's total intangible assets as of September 30, 2014 (in millions):

	Gross Carrying Amount	Accumulated Amortization	Net Carrying Amount
Customer relationships	$ 525.0	$ (23.2)	$ 501.8

The weighted average amortization period for intangible assets is 13.7 years. Amortization expense for intangibles was approximately $10.2 million and $23.2 million for the three and nine months ended September 30, 2014, respectively.

The following table summarizes the Partnership's estimated aggregate amortization expense for the identified periods (in millions):

2014 (remaining)	$	10.2
2015		41.0
2016		41.0
2017		41.0
2018		41.0
Thereafter		327.6
Total	$	501.8

(k) Asset Retirement Obligations

The Partnership recognizes liabilities for retirement obligations associated with its pipelines and processing and fractionation facilities. Such liabilities are recognized when there is a legal obligation associated with the retirement of the assets and the amount can be reasonably estimated. The initial measurement of an asset retirement obligation is recorded as a liability at its fair value, with an offsetting asset retirement cost recorded as an increase to the associated property, plant and equipment. If the fair value of a recorded asset retirement obligation changes, a revision is recorded to both the asset retirement obligation and the asset retirement cost. The Partnership's retirement obligations include estimated environmental remediation costs which arise from normal operations and are associated with the retirement of the long-lived assets. The asset retirement cost is depreciated using the straight line depreciation method similar to that used for the associated property, plant and equipment.

(l) Other Long-Term Liabilities

Included in other current and long-term liabilities is an $85.2 million total liability related to an onerous performance obligation assumed in the business combination. The Partnership has one delivery contract which requires it to deliver a specified volume of gas each month at an indexed base price with a term to 2019. The Partnership realizes a loss on the delivery of gas under this contract each month based on current prices. The fair value of this onerous performance obligation was recorded as a result of the March 7, 2014 business combination and was based on forecasted discounted cash obligations in excess of market under this gas delivery contract. The liability is reduced each month as delivery is made over the remaining life of the contract with an offsetting reduction in purchase gas costs.

(m) Derivatives

The Partnership uses derivative instruments to hedge against changes in cash flows related to product price, as opposed to their use for trading purposes. We generally determine the fair value of swap contracts based on the difference between the derivative's fixed contract price and the underlying market price at the determination date. The asset or liability related to the derivative instruments is recorded on the balance sheet as fair value of derivative assets or liabilities in accordance with FASB ASC 815. Changes in fair value of derivative instruments are recorded in gain (loss) on derivative activity in the period of change.

Realized gains and losses on commodity related derivatives are recorded as gain or loss on derivative activity within revenues in the consolidated statement of operations in the period incurred. Settlements of derivatives are included in cash flows from operating activities.

(n) Concentrations of Credit Risk

Financial instruments, which potentially subject the Partnership to concentrations of credit risk, consist primarily of trade accounts receivable and derivative financial instruments. Management believes the risk is limited, other than the Partnership's exposure to Devon discussed below, since the Partnership's customers represent a broad and diverse group of energy marketers and end users. In addition, the Partnership continually monitors and reviews credit exposure to its marketing counter-parties and letters of credit or other appropriate security are obtained as considered necessary to limit the risk of loss. The Partnership records reserves for uncollectible accounts on a specific identification basis since there is not a large volume of late paying customers. The Partnership had no reserve for uncollectible receivables as of September 30, 2014.

During the three and nine months ended September 30, 2014 and 2013, the Partnership had no third party customer that individually represented greater than 10.0% of its consolidated midstream revenues other than affiliate transactions with Devon which represented 24.2% and 34.9% of the consolidated midstream revenues for the three and nine months ended September 30, 2014, respectively, and 91.9% and 92.0% for the three and nine months ended September 30, 2013, respectively. As the Partnership continues to grow and expand, the relationship between individual customer sales and consolidated total sales is expected to continue to change. Devon represents a significant percentage of revenues and the loss of Devon as a customer would have a material adverse impact on the Partnership's results of operations because the gross operating margin received from transactions with this customer is material to the Partnership.

(o) Environmental Costs

Environmental expenditures are expensed or capitalized as appropriate, depending on the nature of the expenditures and their future economic benefit. Expenditures that relate to an existing condition caused by past operations that do not contribute to current or future revenue generation are expensed. Liabilities for these expenditures are recorded on an undiscounted basis (or a discounted basis when the obligation can be settled at fixed and determinable amounts) when environmental assessments or clean-ups are probable and the costs can be reasonably estimated. For the three and nine months ended September 30, 2014, such expenditures were not material.

(p) Unit-Based Awards

Prior to the business combination, Devon granted certain share-based awards to members of its board of directors and selected employees. The Predecessor did not grant share-based awards because it previously participated in Devon’s share-based award plans since the Predecessor comprised Devon's U.S. midstream assets. The awards granted under Devon’s plans were measured at fair value on the date of grant and were recognized as expense over the applicable requisite service periods.

The Partnership recognizes compensation cost related to all unit-based awards in its consolidated financial statements in accordance with FASB ASC 718. The Partnership and ENLC each have similar unit-based payment plans for employees. Unit-based compensation associated with ENLC's unit-based compensation plans awarded to directors, officers and employees of the General Partner of the Partnership are recorded by the Partnership since ENLC has no substantial or managed operating activities other than its interests in the Partnership and Midstream Holdings.

(q) Commitments and Contingencies

Liabilities for loss contingencies arising from claims, assessments, litigation or other sources are recorded when it is probable that a liability has been incurred and the amount can be reasonably estimated.

(r) Discontinued Operations

The Partnership classifies as discontinued operations its assets or asset groups that have clearly distinguishable cash flows and are in the process of being sold or have been sold. The Partnership also includes as discontinued operations Predecessor assets that were not contributed in the business combination.

(s) Debt Issue Costs

Costs incurred in connection with the issuance of long-term debt are deferred and recorded as interest expense over the term of the related debt. Gains or losses on debt repurchases, redemptions and debt extinguishments include any associated unamortized debt issue costs.

(t) Recent Accounting Pronouncements

In May 2014, the Financial Accounting Standards Board issued Accounting Standards Update ("ASU") 2014-09, *Revenue from Contracts with Customers* ("ASU 2014-09"). ASU 2014-09 will replace existing revenue recognition requirements in US GAAP and will require entities to recognize revenue at an amount that reflects the consideration to which the Partnership expects to be entitled in exchange for transferring goods or services to a customer. The new standard also requires significantly expanded disclosures regarding the qualitative and quantitative information of an entity's nature, amount, timing, and uncertainty of revenue and cash flows arising from contracts with customers. ASU 2014-09 is effective for annual reporting periods beginning after December 15, 2016, including interim periods within that reporting period and is to be applied retrospectively, with early application not permitted. We are currently evaluating the impact the pronouncement will have on our consolidated financial statements and related disclosures. Subject to this evaluation, we have reviewed all recently issued accounting pronouncements that became effective during the nine months ended September 30, 2014, and have determined that none would have a material impact on our Condensed Consolidated Financial Statements.

(3) Acquisition

On March 7, 2014, the Partnership acquired, through one of its wholly owned subsidiaries, 50% of the outstanding equity interests in Midstream Holdings and all of the outstanding equity interests in EnLink Midstream Holdings GP, LLC, the general partner of Midstream Holdings, in exchange for the issuance by the Partnership of 120,542,441 units representing a new class of limited partnership interests in the Partnership (the "Class B Units"). Midstream Holdings owns midstream assets in the Barnett Shale in North Texas and the Cana-Woodford and Arkoma-Woodford Shales in Oklahoma, as well as a contractual right to the burdens and benefits of Devon's 38.75% interest in Gulf Coast Fractionator ("GCF") in Mt. Belvieu, Texas.

Under the acquisition method of accounting, Midstream Holdings is the acquirer in the business combination because its parent company, Devon, obtained control of the Partnership through the indirect control of the General Partner. Consequently, Midstream Holdings' assets and liabilities retained their carrying values and the Partnership's assets acquired and liabilities assumed by Midstream Holdings as the Predecessor in the business combination have been recorded at their fair values measured as of the acquisition date. The excess of the purchase price over the estimated fair values of the Partnership's net assets acquired has been recorded as goodwill.

Since equity consideration was issued for this business combination, the purchase of these assets and liabilities has been excluded from our statement of cash flows, except for transaction related costs totaling $34.7 million assumed by the Partnership at closing and subsequently paid by the Partnership.

The following table summarizes the purchase price (in millions, except per unit price):

EnLink Midstream Partners, LP outstanding units:		
Common units held by public unitholders		75.1
Common units held by EMI		18.0
Preferred units held by third party (1)		17.1
Restricted units		0.4
Total units exchanged		110.6
EnLink Midstream Partners, LP common unit price (2)	$	30.51
EnLink Midstream Partners, LP common units fair value	$	3,374.4
EnLink Midstream Partners, LP outstanding unit options fair value	$	3.9
Total purchase price	$	3,378.3

(1) The Partnership converted the preferred units to common units in February 2014.

(2) The final purchase price is based on the market value of the Partnership's common units as of the closing date, March 7, 2014.

The following table is a summary of the preliminary fair value of the assets acquired and liabilities assumed from the Partnership in the business combination as of March 7, 2014 (in millions):

Assets acquired:		
Current assets	$	435.9
Property, plant and equipment		2,341.9
Intangibles assets		524.9
Equity investment		221.5
Goodwill		1,856.0
Other long-term assets		1.1
Liabilities assumed:		
Current liabilities		(474.0)
Long-term debt		(1,364.3)
Deferred taxes		(63.6)
Other long-term liabilities		(101.1)
Net assets acquired	$	3,378.3

Goodwill recognized from the business combination primarily relates to the value created from additional growth opportunities and greater operating leverage in core areas. The goodwill is allocated among our Texas, Louisiana, Oklahoma, and ORV segments. The purchase price allocation has been prepared on a preliminary basis pending receipt of a final valuation report and is subject to change. All of the goodwill is non-deductible for tax purposes.

For the period from March 7, 2014 to September 30, 2014, the Partnership recognized $1,661.7 million of revenues and $1,636.7 million of operating expenses related to the assets acquired in the business combination.

Pro Forma Information

The following unaudited pro forma condensed financial information for the nine months ended September 30, 2014 and 2013 gives effect to the business combination as if it had occurred on January 1, 2013. The unaudited pro forma condensed financial information has been included for comparative purposes only and is not necessarily indicative of the results that might have occurred had the transactions taken place on the dates indicated and is not intended to be a projection of future results. As of March 7, 2014, Midstream Holdings entered into gathering and processing agreements with Devon, which are described in Note 4. Pro forma financial information associated with the business combination and with these agreements with Devon is reflected below.

	Three Months Ended	Nine Months Ended	
	September 30, 2013	September 30, 2014	September 30, 2013
	(in millions, except for per unit data)		
Pro forma total revenues	$ 621.6	$ 2,667.9	$ 1,818.4
Pro forma net income	$ 5.5	$ 217.3	$ 114.0
Pro forma net income attributable to EnLink Midstream Partners, LP	$ (24.4)	$ 101.2	$ 30.3
Pro forma net income per common unit:			
Basic	$ (0.13)	$ 0.38	$ 0.11
Diluted	$ (0.13)	$ 0.38	$ 0.11

(4) Affiliate Transactions

The Partnership engages in various transactions with Devon and other affiliated entities. Prior to March 7, 2014, these transactions relate to Predecessor transactions consisting of sales to and from affiliates, services provided by affiliates, cost allocations from affiliates and centralized cash management activities performed by affiliates. Management believes these transactions are executed on terms that are fair and reasonable and are consistent with terms for transactions with nonaffiliated third parties. The amounts related to affiliate transactions are specified in the accompanying financial statements.

The Predecessor's historical assets comprised all of Devon's U.S. midstream assets and operations. However, only its assets serving the Barnett, Cana-Woodford and Arkoma-Woodford Shales, as well as contractual rights to the burdens and benefits of Devon's 38.75% interest in GCF, were contributed to Midstream Holdings in connection with the business combination. Assets that were not contributed from the Predecessor are reflected as discontinued operations prior to March 7, 2014 and reflected as a reduction in equity at March 7, 2014. Further, the Predecessor's historical combined financial statements include U.S. federal and state income tax expense. As a result of the business combination, Midstream Holdings is a legal entity that is treated as a partnership for tax purposes and is not subject to U.S. federal income tax or certain state income taxes in the future. The business combination transactions were treated as a reorganization under common control for tax purposes. Therefore, the elimination of the related deferred tax liability is reflected as an increase in equity.

Midstream Holdings, in which the Partnership holds a 50% economic interest as of March 7, 2014, conducts business with Devon pursuant to the gathering and processing agreements described below. The legacy Partnership also historically has maintained a relationship with Devon as a customer, as described in more detail below.

Gathering and Processing Agreements

As described in Note 1, Midstream Holdings was previously a wholly-owned subsidiary of Devon, and all of its assets were contributed to it by Devon. In connection with the consummation of the business combination, EnLink Midstream Services, LLC, a wholly-owned subsidiary of Midstream Holdings ("EnLink Midstream Services"), entered into 10-year gathering and processing agreements with Devon pursuant to which EnLink Midstream Services provides gathering, treating, compression, dehydration, stabilization, processing and fractionation services, as applicable, for natural gas delivered by Devon Gas Services, L.P., a subsidiary of Devon ("Gas Services") to Midstream Holdings' gathering and processing systems in the Barnett, Cana-Woodford and Arkoma-Woodford Shales. SWG Pipeline, L.L.C. ("SWG Pipeline"), another wholly-owned subsidiary of Midstream Holdings, entered into a 10-year gathering agreement with Devon pursuant to which SWG Pipeline provides gathering, treating, compression, dehydration and redelivery services, as applicable, for natural gas delivered by Gas Services to another of the Partnership's gathering system in the Barnett Shale.

These agreements provide Midstream Holdings with dedication of all of the natural gas owned or controlled by Devon and produced from or attributable to existing and future wells located on certain oil, natural gas and mineral leases covering land within the acreage dedications, excluding properties previously dedicated to other natural gas gathering systems not owned and operated by Devon. Pursuant to the gathering and processing agreements, Devon has committed to deliver specified average minimum daily volumes of natural gas to Midstream Holdings' gathering systems in the Barnett, Cana-Woodford and Arkoma-Woodford Shales during each calendar quarter for a five-year period following execution. Devon is entitled to firm service, meaning that if capacity on a system is curtailed or reduced, or capacity is otherwise insufficient, Midstream Holdings will take delivery of as much Devon natural gas as is permitted in accordance with applicable law.

The gathering and processing agreements are fee-based, and Midstream Holdings is paid a specified fee per MMBtu for natural gas gathered on Midstream Holdings' gathering systems and a specified fee per MMBtu for natural gas processed. The particular fees, all of which are subject to an automatic annual inflation escalator at the beginning of each year, differ from one system to another and do not contain a fee redetermination clause.

On August 29, 2014, Gas Services assigned its 10-year gathering and processing agreement to Linn Exchange Properties, LLC ("Linn Energy"), which is a subsidiary of Linn Energy, LLC, in connection with Gas Services' divestiture of certain of its southeastern Oklahoma assets. Such assignment will be effective as of December 1, 2014. Accordingly, beginning on December 1, 2014, Linn Energy will perform Gas Services' obligations under the agreement, which remains in full force and effect. The assignment of this agreement relates to production dedicated to our Northridge assets in southeastern Oklahoma. Gross operating margin related to our Northridge assets totaled $6.5 million and $22.3 million for the three and nine months ended September 30, 2014, respectively.

Historical Customer Relationship with Devon

As noted above, the Partnership maintained a customer relationship with Devon prior to the business combination pursuant to which certain of the Partnership's subsidiaries provide gathering, transportation, processing and gas lift services to Devon subsidiaries in exchange for fee-based compensation under several agreements with Devon. The terms of these agreements vary, but the agreements expire between March 2015 and July 2021 and they automatically renew for month-to-month or year-to-year periods unless canceled by Devon prior to expiration. In addition, one of the Partnership's subsidiaries has agreements with a subsidiary of Devon pursuant to which the Partnership's subsidiary purchases and sells NGLs and pays or receives, as applicable, a margin-based fee. These NGL purchase and sale agreements have month-to-month terms.

Transition Services Agreement

In connection with the consummation of the business combination, the Partnership entered into a transition services agreement with Devon pursuant to which Devon provides certain services to the Partnership with respect to the business and operations of Midstream Holdings, including IT, accounting, pipeline integrity, compliance management and procurement services, and the Partnership provides certain services to Devon and its subsidiaries, including IT, human resources and other commercial and operational services. The Partnership expects most services under the transition services agreement to end by December 31, 2014.

GCF Agreement

In connection with the closing of the business combination, Midstream Holdings entered into an agreement with a wholly-owned subsidiary of Devon pursuant to which Devon agreed, from and after the closing of the business combination, to hold for the benefit of Midstream Holdings the economic benefits and burdens of Devon’s 38.75% interest in GCF, which owns a fractionation facility in Mont Belvieu, Texas.

Lone Camp Gas Storage Agreement

In connection with the closing of the business combination, Midstream Holdings entered into an agreement with Gas Services under which Midstream Holdings provides gas storage services at its Lone Camp storage facility. Under this agreement, Gas Services reimburses Midstream Holdings for the expenses it incurs in providing the storage services. This agreement has minimal to no impact on Midstream Holdings' annual revenue.

Acacia Transportation Agreement

In connection with the closing of the business combination, Midstream Holdings entered into an agreement with a wholly-owned subsidiary of Devon pursuant to which Midstream Holdings provides transportation services to Devon on its Acacia pipeline.

Office Leases

In connection with the closing of the business combination, the Operating Partnership entered into three office lease agreements with a wholly-owned subsidiary of Devon pursuant to which the Operating Partnership leases office space from Devon at its Bridgeport, Oklahoma City and Cresson office buildings. Rent payable to Devon under these lease agreements is $174,000, $31,000 and $66,000, respectively, on an annual basis.

Tax Sharing Agreement

In connection with the closing of the business combination, the Partnership, ENLC and Devon entered into a tax sharing agreement providing for the allocation of responsibilities, liabilities and benefits relating to any tax for which a combined tax return is due.

The following presents financial information for the Predecessor's affiliate transactions and other transactions with Devon, all of which are settled through an adjustment to equity prior to March 7, 2014 (in millions):

	Three Months Ended September 30,	Nine Months Ended September 30,	
	2013	2014	2013
Continuing Operations:			
Operating revenues - affiliates	$ (531.4)	$ (436.4)	$ (1,557.0)
Operating expenses - affiliates	417.5	340.0	1,229.6
Net affiliate transactions	(113.9)	(96.4)	(327.4)
Capital expenditures	44.7	16.2	201.3
Other third-party transactions, net	(50.8)	53.0	8.4
Net third-party transactions	(6.1)	69.2	209.7
Net cash distributions to Devon - continuing operations	(120.0)	(27.2)	(117.7)
Non-cash distribution of net assets to Devon	—	(23.5)	—
Total net distributions per equity	$ (120.0)	$ (50.7)	$ (117.7)
Discontinued operations:			
Operating revenues - affiliates	$ (20.8)	$ (10.4)	$ (68.1)
Operating expenses - affiliates	7.8	5.0	25.4
Cash used in financing activities - affiliates	(0.4)	—	(5.6)
Net affiliate transactions	(13.4)	(5.4)	(48.3)
Capital expenditures	(0.1)	0.6	5.3
Other third-party transactions, net	(73.5)	0.4	(54.6)
Net third-party transactions	(73.6)	1.0	(49.3)
Net distributions to Devon and non-controlling interests - discontinued operations	(87.0)	(4.4)	(97.6)
Non-cash distribution of net assets to Devon	—	(39.9)	—
Total net distributions per equity	$ (87.0)	$ (44.3)	$ (97.6)
Total distributions- continuing and discontinued operations	$ (207.0)	$ (95.0)	$ (215.3)

For the three and nine months ended September 30, 2014 and 2013, Devon was a significant customer to the Partnership. Devon accounted for 24.2% and 34.9% of the Partnership's revenues for the three and nine months ended September 30, 2014, respectively, and 91.9% and 92.0% for the three and nine months ended September 30, 2013, respectively. The affiliate revenues after March 7, 2014 through September 30, 2014 were $435.6 million. The Partnership had an accounts receivable balance related to transactions with Devon of $113.2 million as of September 30, 2014. The remaining related party receivable balance of $0.6 million is attributable to transactions with ENLC. Additionally, the Partnership had an accounts payable balance related to transactions with Devon of $3.8 million as of September 30, 2014.

Share-based compensation costs included in the management services fee charged to Midstream Holdings by Devon were approximately $2.8 million for the nine months ended September 30, 2014 and $3.5 million and $10.1 million for the three and nine months ended September 30, 2013, respectively. Pension, postretirement and employee savings plan costs included in the management services fee charged to the Partnership by Devon were approximately $1.6 million for the nine months ended September 30, 2014 and $2.2 million and $6.1 million for the three and nine months ended September 30, 2013, respectively. These amounts are included in general and administrative expenses in the accompanying statements of operations.

(5) Long-Term Debt

As of September 30, 2014, long-term debt consisted of the following (in millions):

	September 30, 2014
Bank credit facility (due 2019), interest based on Prime and/or LIBOR plus an applicable margin, interest rate at September 30, 2014 was 1.9%	$ 371.0
Senior unsecured notes (due 2019), net of discount of $2.7 million, which bear interest at the rate of 2.70%	397.3
Senior unsecured notes (due 2022), including a premium of $22.6 million, which bear interest at the rate of 7.125%	185.1
Senior unsecured notes (due 2024), net of discount of $3.5 million, which bear interest at the rate of 4.40%	446.5
Senior unsecured notes (due 2044), net of discount of $3.3 million, which bear interest at the rate of 5.60%	346.8
Debt classified as long-term	$ 1,746.7

Credit Facility. On February 20, 2014, the Partnership entered into a new $1.0 billion unsecured revolving credit facility, which includes a $500.0 million letter of credit subfacility (the “Partnership credit facility”). The Partnership credit facility will mature on the fifth anniversary of the initial funding date, which was March 7, 2014, unless the Partnership requests, and the requisite lenders agree, to extend it pursuant to its terms. The Partnership credit facility contains certain financial, operational and legal covenants. Among other things, these covenants include maintaining a ratio of consolidated indebtedness to consolidated EBITDA (as defined in the Partnership credit facility, which definition includes projected EBITDA from certain capital expansion projects) of no more than 5.0 to 1.0. If the Partnership consummates one or more acquisitions in which the aggregate purchase price is $50.0 million or more, the maximum allowed ratio of consolidated indebtedness to consolidated EBITDA will increase to 5.5 to 1.0 for the quarter of the acquisition and the three following quarters.

Borrowings under the Partnership credit facility bear interest at the Partnership’s option at the Eurodollar Rate (the LIBOR Rate) plus an applicable margin 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. The applicable margins vary depending on the Partnership’s credit rating. Upon breach by the Partnership of certain covenants governing the Partnership credit facility, amounts outstanding under the Partnership credit facility, if any, may become due and payable immediately.

As of September 30, 2014, there were $14.0 million in outstanding letters of credit and $371.0 million in outstanding borrowings under the Partnership’s bank credit facility, leaving approximately $615.0 million available for future borrowing based on the borrowing capacity of $1.0 billion.

The percentages per annum, based upon the debt rating are as set forth below:

Pricing Level	Debt Ratings	Applicable Rate Commitment Fee	EuroDollar Rate/Letter of Credit	Base Rate +
1	A-/A3 or better	0.100%	1.000%	—
2	BBB+/Baa1	0.125%	1.125%	0.125%
3	BBB/Baa2	0.175%	1.250%	0.250%
4	BBB-/Baa3	0.225%	1.500%	0.500%
5	BB+/Ba1	0.275%	1.625%	0.625%
6	BB/Ba2 or worse	0.350%	1.750%	0.750%

Senior Unsecured Notes. On March 7, 2014, the Partnership recorded $725.0 million in aggregate principal amount of 8.875% senior unsecured notes (the “2018 Notes”) due on February 15, 2018 in the business combination. As a result of the business combination, the 2018 Notes were recorded at fair value in accordance with acquisition accounting at an amount of $761.3 million, including a premium of $36.3 million, as of March 7, 2014.

On March 7, 2014, the Partnership recorded $196.5 million in aggregate principal amount of 7.125% senior unsecured notes (the “2022 Notes”) due on June 1, 2022 in the business combination. The interest payments on the 2022 Notes are due semi-annually in arrears in June and December. As a result of the business combination, the 2022 Notes were recorded at fair value in accordance with acquisition accounting at an amount of $226.0 million, including a premium of $29.5 million. On July 20, 2014, the Partnership redeemed $18.5 million aggregate principal amount of the 2022 Notes for $20.0 million, including accrued interest. On September 20, 2014, the Partnership redeemed an additional $15.5 million aggregate principal amount of the 2022 Notes for $17.0 million, including accrued interest. The Partnership recorded a gain on extinguishment of debt related to the redemption of the 2022 Notes of $2.4 million and $3.2 million for the three and nine months ended September 30, 2014, respectively.

On March 12, 2014, the Partnership commenced a tender offer to purchase any and all of the outstanding 2018 Notes. Approximately $536.1 million, or approximately 74%, of the 2018 Notes were validly tendered and on March 19, 2014, the Partnership made a payment of approximately $567.4 million for all such tendered 2018 Notes. Also on March 19, 2014, the Partnership delivered a notice of redemption for any and all outstanding 2018 Notes. All remaining outstanding 2018 Notes were redeemed on April 18, 2014 for $200.2 million, including accrued interest.

On March 19, 2014, the Partnership issued $1.2 billion aggregate principal amount of unsecured senior notes, consisting of $400.0 million aggregate principal amount of its 2.700% senior notes due 2019 (the "2019 Notes"), $450.0 million aggregate principal amount of its 4.400% senior notes due 2024 (the "2024 Notes") and $350.0 million aggregate principal amount of its 5.600% senior notes due 2044 (the "2044 Notes" and, together with the 2018 Notes, 2019 Notes, 2022 Notes and 2024 Notes, the "Senior Notes"), at prices to the public of 99.850%, 99.830% and 99.925%, respectively, of their face value. The 2019 Notes mature on April 1, 2019, the 2024 Notes mature on April 1, 2024 and the 2044 Notes mature on April 1, 2044. The interest payments on the 2019 Notes, 2024 Notes and 2044 Notes are due semi-annually in arrears in April and October.

Prior to June 1, 2017, the Partnership may redeem all or part of the remaining 2022 Notes at the redemption price equal to the sum of the principal amount thereof, plus a make-whole premium at the redemption date, plus accrued and unpaid interest to the redemption date. On or after June 1, 2017, the Partnership may redeem all or a part of the remaining 2022 Notes at redemption prices (expressed as percentages of principal amount) equal to 103.563% for the twelve-month period beginning on June 1, 2017, 102.375% for the twelve-month period beginning on June 1, 2018, 101.188% for the twelve-month period beginning on June 1, 2019 and 100.000% for the twelve-month period beginning on June 1, 2020 and at any time thereafter, plus accrued and unpaid interest, if any, to the applicable redemption date on the 2022 Notes.

Prior to March 1, 2019, the Partnership may redeem all or a part of the 2019 Notes at a redemption price equal to the greater of: (i) 100% of the principal amount of the 2019 Notes to be redeemed; or (ii) the sum of the remaining scheduled payments of principal and interest on the 2019 Notes to be redeemed that would be due after the related redemption date but for such redemption (exclusive of interest accrued to, but excluding, the redemption date) discounted to the redemption date on a semi-annual basis (assuming a 360-day year consisting of twelve 30-day months) at the applicable Treasury Rate plus 20 basis points; plus accrued and unpaid interest to, but excluding, the redemption date. At any time on or after March 1, 2019, the Partnership may redeem all or a part of the 2019 Notes at a redemption price equal to 100% of the principal amount of the 2019 Notes to be redeemed plus accrued and unpaid interest to, but excluding, the redemption date.

Prior to January 1, 2024, the Partnership may redeem all or a part of the 2024 Notes at a redemption price equal to the greater of: (i) 100% of the principal amount of the 2024 Notes to be redeemed; or (ii) the sum of the present values of the remaining scheduled payments of principal and interest on the 2024 Notes to be redeemed that would be due after the related redemption date but for such redemption (exclusive of interest accrued to, but excluding, the redemption date) discounted to the redemption date on a semi-annual basis (assuming a 360-day year consisting of twelve 30-day months) at the applicable Treasury Rate plus 25 basis points; plus accrued and unpaid interest to, but excluding, the redemption date. At any time on or after January 1, 2024, the Partnership may redeem all or a part of the 2024 Notes at a redemption price equal to 100% of the principal amount of the 2024 Notes to be redeemed plus accrued and unpaid interest to, but excluding, the redemption date.

Prior to October 1, 2043, the Partnership may redeem all or a part of the 2044 Notes at a redemption price equal to the greater of: (i) 100% of the principal amount of the 2044 Notes to be redeemed; or (ii) the sum of the present values of the remaining scheduled payments of principal and interest on the 2044 Notes to be redeemed that would be due after the related redemption date but for such redemption (exclusive of interest accrued to, but excluding, the redemption date) discounted to the redemption date on a semi-annual basis (assuming a 360-day year consisting of twelve 30-day months) at the applicable Treasury Rate plus 30 basis points; plus accrued and unpaid interest to, but excluding, the redemption date. At any time on or after October 1, 2043, the Partnership may redeem all or a part of the 2044 Notes at a redemption price equal to 100% of the principal amount of the 2044 Notes to be redeemed plus accrued and unpaid interest to, but excluding, the redemption date.

The indentures governing the Senior Notes contain covenants that, among other things, limit our ability to create or incur certain liens or consolidate, merge or transfer all or substantially all of our assets.

Each of the following is an event of default under the indentures:

- failure to pay any principal or interest when due;
- failure to observe any other agreement, obligation or other covenant in the indenture, subject to the cure periods for certain failures;
- our default under other indebtedness that exceeds a certain threshold amount;
- failure by us to pay final judgments that exceed a certain threshold amount; and
- bankruptcy or other insolvency events involving us.

If an event of default relating to bankruptcy or other insolvency events occurs, the Senior Notes will immediately become due and payable. If any other event of default exists under the indenture, the trustee under the indenture or the holders of the Senior Notes may accelerate the maturity of the Senior Notes and exercise other rights and remedies.

(6) Income Taxes

The Predecessor's historical combined financial statements include U.S. federal and state income tax expense. As a result of the business combination, the Predecessor was reorganized and Midstream Holdings is treated as a partnership and not subject to federal or certain state income taxes subsequent to the March 7, 2014 transaction date. The elimination of the related deferred federal and state income tax liabilities totaling $467.5 million, excluding $8.2 million of deferred taxes related to the Texas margin tax, is reflected through equity and treated as a reorganization under common control.

Net deferred tax liabilities also include $62.5 million of deferred taxes assumed in the business combination with the Partnership on March 7, 2014. The legacy Partnership has a wholly-owned corporate entity that was formed to acquire the common stock of Clearfield Energy, Inc. and assumed the carryover tax basis of the ORV assets acquired from Clearfield. This net deferred tax liability represents the future tax payable on the difference between the fair value and the tax basis of the assets acquired and is expected to become payable no later than 2027.

(7) Partners' Capital

(a) Issuance of Common Units

In May 2014, the Partnership entered into an Equity Distribution Agreement (the "EDA") with BMO Capital Markets Corp. ("BMOCM"). Pursuant to the terms of the EDA, the Partnership may from time to time through BMOCM, as its sales agent, sell common units representing limited partner interests having an aggregate offering price of up to $75.0 million.

Through September 30, 2014, the Partnership sold an aggregate of 2.4 million common units under the EDA, generating proceeds of approximately $71.9 million (net of approximately $0.7 million of commissions to BMOCM). The Partnership used the net proceeds for general partnership purposes, including working capital, capital expenditures and repayments of indebtedness.

(b) Distributions

Unless restricted by the terms of the Partnership's credit facility and/or the indentures governing the Partnership's unsecured senior notes, the Partnership 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 Partnership's first quarter 2014 distribution on its common units and Class B Units of $0.36 per unit and $0.10 per unit, respectively, was paid on May 14, 2014. Distributions declared for the Class B Units represent a pro rata distribution for the number of days the Class B Units were issued and outstanding during the quarter. The Class B Units automatically converted into common units on a one-for-one basis on May 6, 2014. The Partnership declared a second quarter 2014 distribution on its common units of $0.365 per unit which was paid on August 13, 2014. Also, the Partnership declared a third quarter 2014 distribution on its common units of $0.37 per unit to be paid on November 13, 2014.

Our General Partner owns the general partner interest in us and all of our incentive distribution rights. Our General Partner is entitled to receive incentive distributions if the amount we distribute with respect to any quarter exceeds levels specified in our partnership agreement. Under the quarterly incentive distribution provisions, generally our General Partner is entitled to 13.0% of amounts we distribute in excess of $0.25 per unit, 23% of the amounts we distribute in excess of $0.3125 per unit and 48.0% of amounts we distribute in excess of $0.375 per unit.

(c) Earnings per Unit and Dilution Computations

As required under FASB ASC 260-10-45-61A, unvested share-based payments that entitle employees to receive non-forfeitable distributions are considered participating securities, as defined in FASB ASC 260-10-20, for earnings per unit calculations. Net income earned by the Predecessor prior to March 7, 2014 is not included for purposes of calculating earnings per unit as the Predecessor did not have any unitholders. The following table reflects the computation of basic and diluted earnings per limited partner unit for the three and nine months ended September 30, 2014 (in millions except per unit amounts):

	Three Months Ended September 30, 2014	Nine Months Ended September 30, 2014*
Limited partners' interest in net income	$ 40.5	$ 86.5
Distributed earnings allocated to:		
Common units and Class B Units (1) (2)	$ 85.5	$ 220.6
Unvested restricted units (1)	0.4	0.9
Total distributed earnings	$ 85.9	$ 221.5
Undistributed loss allocated to:		
Common units and Class B Units (2)	$ (45.1)	$ (134.6)
Unvested restricted units	(0.2)	(0.5)
Total undistributed loss	$ (45.3)	$ (135.1)
Net income allocated to:		
Common units and Class B Units (2)	$ 40.3	$ 86.1
Unvested restricted units	0.2	0.4
Total limited partners' interest in net income	$ 40.5	$ 86.5
Basic and diluted net income per unit:		
Basic	$ 0.18	$ 0.38
Diluted	$ 0.18	$ 0.38

* The nine months ended September 30, 2014 amounts consist only of the period from March 7, 2014 through September 30, 2014.

(1) Three months ended September 30, 2014 represents a declared distribution of $0.37 per unit for common units payable on November 13, 2014 and nine months ended September 30, 2014 represents distributions of $0.36 per unit paid on May 14, 2014, distributions of $0.365 per unit paid on August 13, 2014 and distributions declared of $0.37 per unit payable on November 13, 2014.

(2) Nine months ended September 30, 2014 includes distribution of $0.10 per unit for Class B Units paid on May 14, 2014. The Class B Units converted into common units on a one-for-one basis on May 6, 2014.

The following are the unit amounts used to compute the basic and diluted earnings per limited partner unit for the three andnine months ended September 30, 2014 (in millions):

	Three Months Ended September 30, 2014	Nine Months Ended September 30, 2014*
Basic weighted average units outstanding:		
Weighted average limited partner basic common units outstanding	231.0	230.3
Diluted weighted average units outstanding:		
Weighted average limited partner basic common units outstanding	231.0	230.3
Dilutive effect of restricted units issued	0.4	0.3
Total weighted average limited partner diluted common units outstanding	231.4	230.6

* The nine months ended September 30, 2014 amounts consist only of the period from March 7, 2014 throughSeptember 30, 2014.

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

Net income is allocated to the General Partner in an amount equal to its incentive distributions as described in Note 7(b). The General Partner's share of net income consists of incentive distributions to the extent earned, a deduction for unit-based compensation attributable to ENLC's restricted units and the percentage interest of the Partnership's net income adjusted for ENLC's unit-based compensation specifically allocated to the General Partner. The net income allocated to the General Partner is as follows for the three and nine months ended September 30, 2014 (in millions

	Three Months Ended September 30, 2014	Nine Months Ended September 30, 2014*
Income allocation for incentive distributions	$ 6.3	$ 13.6
Unit-based compensation attributable to ENLC's restricted units	(3.1)	(6.8)
General Partner interest in net income	0.3	0.7
General Partner share of net income	$ 3.5	$ 7.5

* The nine months ended September 30, 2014 amounts consist only of the period from March 7, 2014 throughSeptember 30, 2014.

(8) Asset Retirement Obligations

The schedule below summarizes the changes in the Partnership's asset retirement obligations:

	September 30, 2014	September 30, 2013
	(in millions)	
Beginning asset retirement obligations	$ 7.7	$ 9.1
Revisions to existing liabilities	2.2	0.4
Liabilities acquired	0.5	—
Accretion	0.4	0.3
Ending asset retirement obligations	$ 10.8	$ 9.8

(9) Investment in Unconsolidated Affiliates

The Partnership's unconsolidated investments consisted of a contractual right to the benefits and burdens associated with Devon's38.75% ownership interest in GCF at September 30, 2014 and December 31, 2013 and a 30.6% ownership interest in Howard Energy Partners ("HEP") at September 30, 2014.

The following table shows the activity related to the Partnership's investment in unconsolidated affiliates for the periods indicated (in millions):

	Gulf Coast Fractionators	Howard Energy Partners (1)	Total
Three months ended			
September 30, 2014			
Distributions	$ 5.2	$ 3.0	$ 8.2
Equity in income	$ 5.2	$ 0.4	$ 5.6
September 30, 2013			
Distributions	$ 12.0	$ —	$ 12.0
Equity in income	$ 5.8	$ —	$ 5.8
Nine months ended			
September 30, 2014 (1)			
Distributions	$ 5.2	$ 8.7	$ 13.9
Equity in income	$ 13.2	$ 1.1	$ 14.3
September 30, 2013			
Distributions	$ 12.0	$ —	$ 12.0
Equity in income	$ 10.2	$ —	$ 10.2

(1) Includes income and distributions for the period from March 7, 2014 throughSeptember 30, 2014.

The following table shows the balances related to the Partnership's investment in unconsolidated affiliates for the periods indicated (in millions):

	September 30, 2014	December 31, 2013
Gulf Coast Fractionators (1)	$ 56.0	$ 61.1
Howard Energy Partners	220.1	—
Total investments in unconsolidated affiliates	$ 276.1	$ 61.1

(1) Devon retained $13.1 million of the undistributed earnings due from GCF, as of March 7, 2014 when the GCF contractual right allocating the benefits and burdens of the 38.75% ownership interest in GCF to the Partnership became effective. The$13.1 million of the undistributed earnings was reflected as a reduction in the GCF investment on March 7, 2014.

(10) Employee Incentive Plans

(a) Long-Term Incentive Plans

The Partnership and ENLC each have similar unit or unit-based payment plans for employees, which are described below. Unit-based compensation associated with ENLC's unit-based compensation plan awarded to officers and employees of the Partnership are recorded by the Partnership since ENLC has no substantial or managed operating activities other than its interests in the Partnership and Midstream Holdings. Amounts recognized in the condensed consolidated financial statements with respect to these plans are as follows (in millions):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
Cost of unit-based compensation allocated to Predecessor general and administrative expense (1)	$ —	$ 3.5	$ 2.8	$ 10.1
Cost of unit-based compensation charged to general and administrative expense	4.9	—	10.9	—
Cost of unit-based compensation charged to operating expense	0.8	—	1.8	—
Total amount charged to income	$ 5.7	$ 3.5	$ 15.5	$ 10.1

(1) Unit-based compensation expense was treated as a contribution by the Predecessor in the Consolidated Statement of Changes in Partners' Equity.

The Partnership accounts for unit-based compensation in accordance with FASB ASC 718, which requires that compensation related to all unit-based awards, including unit options, be recognized in the consolidated financial statements. On March 7, 2014, the General Partner amended and restated the amended and restated EnLink Midstream GP, LLC Long-Term Incentive Plan (the "Plan") (formerly the Crosstex Energy GP, LLC Long-Term Incentive Plan). Amendments to the Plan included a change in name and other technical amendments. The Plan provides for the issuance of up to 9,070,000 awards.

(b) Restricted Incentive Units

The 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 nine months ended September 30, 2014 is provided below:

	Nine Months Ended September 30, 2014	
EnLink Midstream Partners, LP Restricted Incentive Units:	**Number of Units**	**Weighted Average Grant-Date Fair Value**
Non-vested, beginning of period	—	$ —
Assumed in business combination	371,225	30.51
Granted	701,119	31.65
Vested*	(39,833)	30.63
Forfeited	(13,196)	31.83
Non-vested, end of period	1,019,315	$ 31.27
Aggregate intrinsic value, end of period (in millions)	$ 31.0	

* Vested units include16,471 units withheld for payroll taxes paid on behalf of employees.

Restricted incentive units assumed in the business combination were valued as of March 7, 2014, will vest at the end oftwo years and are included in the restricted incentive units outstanding and the current unit-based compensation cost calculations at September 30, 2014. The Partnership issued restricted incentive units in 2014 to officers and other employees. These restricted incentive units typically vest at the end of three years.

A summary of the restricted incentive units' aggregate intrinsic value (market value at vesting date) and fair value of units vested during the three and nine months ended September 30, 2014 are provided below (in millions):

EnLink Midstream Partners, LP Restricted Incentive Units:	Three Months Ended September 30, 2014	Nine Months Ended September 30, 2014
Aggregate intrinsic value of units vested	$ 1.2	$ 1.2
Fair value of units vested	$ 1.2	$ 1.2

As of September 30, 2014, there was $21.3 million of unrecognized compensation cost related to non-vested restricted incentive units. That cost is expected to be recognized over a weighted-average period of 2.1 years.

(c) Unit Options

During the nine months ended September 30, 2014, 31,382 unit options of the Partnership were exercised with an intrinsic value of $0.6 million. As of September 30, 2014, all unit options were fully vested and fully expensed.

(d) EnLink Midstream, LLC's Restricted Incentive Units

On February 5, 2014, ENLC's sole unitholder at the time, EnLink Midstream Manager, LLC, approved the EnLink Midstream, LLC 2014 Long-Term Incentive Plan (the "Company Plan"). The Company Plan provides for the issuance of 11.0 million awards.

On March 7, 2014, effective as of the closing of the business combination, ENLC (i) assumed the Crosstex Energy, Inc. 2009 Long-Term Incentive Plan (the "2009 Plan") and all awards thereunder outstanding following the business combination and (ii) amended and restated the 2009 Plan to reflect the conversion of the awards under the 2009 Plan relating to EMI's common stock to awards in respect of common units of ENLC.

ENLC's restricted incentive units are valued at their fair value at the date of grant which is equal to the market value of the common units on such date. A summary of the restricted incentive units activities for the nine months ended September 30, 2014 is provided below:

	Nine Months Ended September 30, 2014	
EnLink Midstream, LLC Restricted Incentive Units:	Number of Units	Weighted Average Grant-Date Fair Value
Non-vested, beginning of period	—	$ —
Assumed in business combination	435,674	37.60
Granted	626,341	36.59
Vested*	(59,553)	37.56
Forfeited	(11,859)	36.54
Non-vested, end of period	990,603	$ 36.97
Aggregate intrinsic value, end of period (in millions)	$ 40.9	

* Vested units include 24,727 units withheld for payroll taxes paid on behalf of employees.

Restricted incentive units assumed in the business combination were valued as of March 7, 2014, will vest at the end of two years and are included in restricted incentive units outstanding and the current unit-based compensation cost calculations at September 30, 2014. ENLC issued restricted incentive units in 2014 to officers and other employees. These restricted incentive units typically vest at the end of three years and are included in restricted incentive units outstanding.

A summary of the restricted incentive units' aggregate intrinsic value (market value at vesting date) and fair value of units vested during the three and nine months ended September 30, 2014 are provided below (in millions):

EnLink Midstream, LLC Restricted Incentive Units:	Three Months Ended September 30, 2014	Nine Months Ended September 30, 2014
Aggregate intrinsic value of units vested	$ 2.4	$ 2.4
Fair value of units vested	$ 2.2	$ 2.2

As of September 30, 2014, there was $23.3 million of unrecognized compensation costs related to non-vested ENLC restricted incentive units. The cost is expected to be recognized over a weighted average period of 2.1 years.

(11) Derivatives

Commodity Swaps

The Partnership manages its exposure to fluctuation 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 natural gas and NGLs. The Partnership does not designate transactions as cash flow or fair value hedges for hedge accounting treatment under FASB ASC 815. Therefore, changes in the fair value of the Partnership's derivatives are recorded in revenue in the period incurred. In addition, the risk management policy does not allow the Partnership to take speculative positions with its derivative contracts.

The Partnership commonly enters into index (float-for-float) or fixed-for-float swaps in order to mitigate its 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 the Partnership receives a percentage of liquids as a fee for processing third-party gas, 2) in the natural gas processing and fractionation components of our business and 3) where the Partnership is 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 relating to commodity swaps are as follows for the three and nine months ended September 30, 2014 (in millions):

	Three Months Ended September 30, 2014	Nine Months Ended September 30, 2014*
Change in fair value of derivatives	$ 1.8	$ (0.2)
Realized losses on derivatives	(0.8)	(1.7)
Gain (loss) on derivative activity	$ 1.0	$ (1.9)

* The nine months ended September 30, 2014 amounts consist only of the period from March 7, 2014 through September 30, 2014.

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

	September 30, 2014
Fair value of derivative assets — current	$ 1.1
Fair value of derivative assets — long term	0.2
Fair value of derivative liabilities — current	(0.9)
Fair value of derivative liabilities — long term	(0.6)
Net fair value of derivatives	$ (0.2)

Set forth below is the summarized notional volumes and fair value of all instruments held for price risk management purposes and related physical offsets at September 30, 2014. The remaining term of the contracts extend no later than December 2016.

			September 30, 2014	
Commodity	Instruments	Unit	Volume	Fair Value
			(In millions)	
NGL (short contracts)	Swaps	Gallons	(61.3)	$ 0.7
NGL (long contracts)	Swaps	Gallons	47.9	(0.9)
Natural Gas (short contracts)	Swaps	MMBtu	(2.2)	0.1
Natural Gas (long contracts)	Swaps	MMBtu	0.4	(0.1)
Total fair value of derivatives				$ (0.2)

On all transactions where the Partnership is exposed to counterparty risk, the Partnership analyzes the counterparty's financial condition prior to entering into an agreement, establishes limits and monitors the appropriateness of these limits on an ongoing basis. The Partnership primarily deals with two types of counterparties, financial institutions and other energy companies, when entering into financial derivatives on commodities. The Partnership has 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 the Partnership's counterparties failed to perform under existing swap contracts, the Partnership's maximum loss as of September 30, 2014 of $1.3 million would be reduced to $0.2 million due to the offsetting of gross fair value payables against gross fair value receivables as allowed by the ISDAs.

Fair Value of Derivative Instruments

Assets and liabilities related to the Partnership's derivative contracts are included in the fair value of derivative assets and liabilities and the profit and loss on the mark to market value of these contracts are recorded net as a loss on derivatives in the consolidated statement of operations. The Partnership estimates the fair value of all of its derivative contracts using actively quoted prices. The estimated fair value of derivative contracts by maturity date was as follows (in millions):

	Maturity Periods			
	Less than one year	One to two years	More than two years	Total fair value
September 30, 2014	$ 0.2	$ (0.3)	$ (0.1)	$ (0.2)

(12) Fair Value Measurements

FASB ASC 820 sets forth a framework for measuring fair value and required disclosures about fair value measurements of assets and liabilities. Fair value under FASB 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.

FASB ASC 820 establishes 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.

The Partnership's 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 liabilities measured at fair value on a recurring basis are summarized below (in millions):

	September 30, 2014 Level 2
Commodity Swaps*	$ (0.2)
Total	$ (0.2)

* The fair value of derivative contracts included in assets or liabilities for risk management activities represents the amount at which the instruments could be exchanged in a current arms-length transaction adjusted for credit risk of the Partnership and/or the counterparty as required under FASB ASC 820.

Fair Value of Financial Instruments

The estimated fair value of the Partnership's financial instruments has been determined by the Partnership 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 the Partnership could realize upon the sale or refinancing of such financial instruments (in millions):

	September 30, 2014	
	Carrying Value	Fair Value
Long-term debt	$ 1,746.7	$ 1,809.2
Obligations under capital leases	$ 20.7	$ 20.3

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

The Partnership had $371.0 million in outstanding borrowings under its revolving credit facility as of September 30, 2014. As borrowings under the credit facility accrue interest under floating interest rate structures, the carrying value of such indebtedness approximates fair value for the amounts outstanding under the credit facility. As of September 30, 2014, the Partnership had borrowings totaling $397.3 million, $446.5 million and $346.8 million, net of discount, under the 2019 Notes, 2024 Notes and 2044 Notes, with a fixed rate of 2.70%, 4.40% and 5.60%, respectively. Additionally, the Partnership had borrowings of $185.1 million, including premium, under the 2022 Notes with a fixed rate of 7.125% as of September 30, 2014. The fair value of all senior unsecured notes as of September 30, 2014 was based on Level 2 inputs from third-party market quotations. The fair value of obligations under capital leases was calculated using Level 2 inputs from third-party banks.

(13) Commitments and Contingencies

(a) Employment and Severance Agreements

Certain members of management of the Partnership are parties to employment and/or severance agreements with the General Partner. The employment and severance agreements provide those managers with severance payments in certain circumstances and, in the case of employment agreements, prohibit each such person from competing with the General Partner or its affiliates for a certain period of time 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, brine and other products is subject to stringent and complex laws and regulations pertaining to health, safety and the environment. As an owner or operator of these facilities, the Partnership 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 the Partnership's results of operations, financial condition or cash flows.

(c) Litigation Contingencies

The Partnership is 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 its financial position or results of operations.

At times, the Partnership's subsidiaries acquire pipeline easements and other property rights by exercising rights of eminent domain and common carrier. As a result, the Partnership (or its subsidiaries) is a party to a number of lawsuits under which a court will determine the value of pipeline easements or other property interests obtained by the Partnership's 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, the Partnership does not expect that awards in these matters will have a material adverse impact on its consolidated results of operations or financial condition.

The Partnership (or its subsidiaries) is defending lawsuits filed by owners of property located near processing facilities or compression facilities constructed by the Partnership as part of its 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. The Partnership's subsidiary, Crosstex LIG, LLC, is one of the named defendants as the owner of pipelines in the area. The validity of the causes of action, as well as the Partnership's costs and legal exposure, if any, related to the lawsuit are not currently determinable. The Partnership intends to vigorously defend the case.

In June 2014, a group of landowners in Assumption Parish, Louisiana added a subsidiary of the Partnership, EnLink Processing Services, LLC, as a defendant in a pending lawsuit they had filed against Texas Brine Company, LLC, Occidental Chemical Corporation, and Vulcan Materials Company relating to claims arising from the August 2012 sinkhole that formed in the Bayou Corne area of Assumption Parish, Louisiana. The suit is pending in the 23rd Judicial Court, Assumption Parish, Louisiana. Although plaintiffs' claims against the other defendants have been pending since October 2012, plaintiffs are now alleging that EnLink Processing Services, LLC's negligence also contributed to the formation of the sinkhole. The amount of damages is unspecified. The validity of the causes of action, as well as the Partnership's costs and legal exposure, if any, related to the lawsuit are not currently determinable. The Partnership intends to vigorously defend the case. The Partnership has also filed a claim for defense and indemnity with its insurers.

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 these pipelines and underground storage reservoirs. We are assessing the potential for recovering our losses from responsible parties. We have sued Texas Brine, LLC, the operator of a failed cavern in the area, and its insurers seeking recovery for this damage. We also filed a claim with our insurers. Our insurers denied our claim. We dispute the denial but have agreed to stay the matter pending resolution of our claims against Texas Brine and its insurers. In August 2014, we received a partial settlement in the amount of $6.1 million. Additional claims related to this matter remain outstanding. We cannot give assurance that we will be able to fully recover our losses through insurance recovery or claims against responsible parties.

In October 2014, Williams Olefins, L.L.C. filed a lawsuit against a subsidiary of the Partnership, EnLink NGL Marketing, LP, in the District Court of Tulsa County, Oklahoma. The plaintiff alleges breach of contract and negligent misrepresentation relating to an ethane output contract between the parties and the subsidiary's termination of ethane production from one of its fractionation plants. The amount of damages is unspecified. The validity of the causes of action, as well as the Partnership's costs and legal exposure, if any, related to the lawsuit are not currently determinable. The Partnership intends to vigorously defend the case.

(14) Segment Information

Identification of the Partnership's operating segments is based principally upon geographic regions served. The Partnership's reportable segments consist of the following: natural gas gathering, processing, transmission and fractionation operations located in north Texas, south 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 the ORV. Operating activity for intersegment eliminations is shown in the corporate segment. The Partnership's sales are derived from external domestic customers.

Corporate expenses include general partnership expenses associated with managing all reportable operating segments. Corporate assets consist primarily of cash, property and equipment, including software, for general corporate support, debt financing costs and investments in HEP and GCF. The Partnership evaluates the performance of its operating segments based on operating revenues and segment profits.

Summarized financial information concerning the Partnership’s reportable segments is shown in the following tables:

	Texas	Louisiana	Oklahoma	Ohio River Valley	Corporate	Totals
			(In millions)			
Three Months Ended September 30, 2014						
Sales to external customers	$ 77.3	$ 491.3	$ —	$ 75.5	$ —	$ 644.1
Sales to affiliates	148.9	39.5	45.9	—	(28.0)	206.3
Purchased gas, NGLs, condensate and crude oil	(76.8)	(486.9)	—	(61.5)	28.0	(597.2)
Operating expenses	(36.2)	(23.7)	(7.0)	(8.9)	—	(75.8)
Gain on litigation settlement	—	6.1	—	—	—	6.1
Gain on derivative activity	—	—	—	—	1.0	1.0
Segment profit	$ 113.2	$ 26.3	$ 38.9	$ 5.1	$ 1.0	$ 184.5
Depreciation and amortization	$ (31.6)	$ (19.1)	$ (11.8)	$ (8.2)	$ (0.9)	$ (71.6)
Goodwill	$ 1,168.2	$ 786.8	$ 190.3	$ 112.5	$ —	$ 2,257.8
Capital expenditures	$ 79.7	$ 79.1	$ 2.5	$ 25.4	$ 3.9	$ 190.6
Three Months Ended September 30, 2013						
Sales to external customers	$ 32.9	$ —	$ 13.9	$ —	$ —	$ 46.8
Sales to affiliates	359.4	—	172.0	—	—	531.4
Purchased gas, NGLs, condensate and crude oil	(286.2)	—	(149.3)	—	—	(435.5)
Operating expenses	(26.9)	—	(8.9)	—	—	(35.8)
Segment profit	$ 79.2	$ —	$ 27.7	$ —	$ —	$ 106.9
Depreciation and amortization	$ (29.0)	$ —	$ (19.0)	$ —	$ —	$ (48.0)
Goodwill	$ 325.4	$ —	$ 76.3	$ —	$ —	$ 401.7
Capital expenditures	$ 27.1	$ —	$ 10.0	$ —	$ —	$ 37.1
Nine Months Ended September 30, 2014						
Sales to external customers	$ 214.3	$ 1,221.9	$ 11.5	$ 180.2	$ —	$ 1,627.9
Sales to affiliates	637.7	41.7	256.0	—	(63.4)	872.0
Purchased gas, NGLs, condensate and crude oil	(423.0)	(1,158.2)	(133.8)	(146.4)	63.4	(1,798.0)
Operating expenses	(106.5)	(45.5)	(20.9)	(20.4)	—	(193.3)
Gain on litigation settlement	—	6.1	—	—	—	6.1
Gain on derivative activity	—	—	—	—	(1.9)	(1.9)
Segment profit (loss)	$ 322.5	$ 66.0	$ 112.8	$ 13.4	$ (1.9)	$ 512.8
Depreciation and amortization	$ (91.7)	$ (43.4)	$ (37.6)	$ (18.1)	$ (1.5)	$ (192.3)
Goodwill	$ 1,168.2	$ 786.8	$ 190.3	$ 112.5	$ —	$ 2,257.8
Capital expenditures	$ 180.2	$ 222.4	$ 10.5	$ 27.7	$ 12.6	$ 453.4
Nine Months Ended September 30, 2013						
Sales to external customers	$ 96.6	$ —	$ 39.5	$ —	$ —	$ 136.1
Sales to affiliates	1,052.3	—	504.7	—	—	1,557.0
Purchased gas, NGLs, condensate and crude oil	(838.7)	—	(440.9)	—	—	(1,279.6)
Operating expenses	(92.0)	—	(24.0)	—	—	(116.0)
Segment profit	$ 218.2	$ —	$ 79.3	$ —	$ —	$ 297.5
Depreciation and amortization	$ (82.4)	$ —	$ (56.2)	$ —	$ —	$ (138.6)
Goodwill	$ 325.4	$ —	$ 76.3	$ —	$ —	$ 401.7
Capital expenditures	$ 113.9	$ —	$ 58.7	$ —	$ —	$ 172.6

The table below presents information about segment assets as ofSeptember 30, 2014 and December 31, 2013:

	September 30, 2014	December 31, 2013
Segment Identifiable Assets:	(In millions)	
Texas	$ 3,236.9	$ 1,460.0
Louisiana	2,925.3	—
Oklahoma	894.5	777.1
Ohio River Valley	513.6	—
Corporate	347.3	72.7
Total identifiable assets	$ 7,917.6	$ 2,309.8

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
Segment profits	$ 184.5	$ 106.9	$ 512.8	$ 297.5
General and administrative expenses	(22.8)	(10.8)	(62.8)	(32.3)
Depreciation and amortization	(71.6)	(48.0)	(192.3)	(138.6)
Operating income	$ 90.1	$ 48.1	$ 257.7	$ 126.6

(15) Discontinued Operations

The Predecessor's historical assets comprised all of Devon's U.S. midstream assets and operations. However, only its assets serving the Barnett, Cana-Woodford and Arkoma-Woodford Shales, as well as contractual rights to the benefits and burdens associated with Devon's 38.75% interest in GCF, were contributed to Midstream Holdings in connection with the business combination on March 7, 2014. Therefore, the Predecessor's non-contributed historical assets and liabilities are presented as held for sale as of December 31, 2013. All operations activity related to the non-contributed assets prior to March 7, 2014 are classified as discontinued operations.

The following schedule summarizes net income from discontinued operations (in millions):

	Three Months Ended September 30,	Nine Months Ended September 30,	
	2013	2014	2013
Operating revenues:			
Operating revenues	$ 10.9	$ 6.8	$ 33.5
Operating revenues - affiliates	20.8	10.5	68.1
Total operating revenues	31.7	17.3	101.6
Operating expenses:			
Operating expenses	37.9	15.7	91.7
Total operating expenses	37.9	15.7	91.7
Income (loss) before income taxes	(6.2)	1.6	9.9
Income tax provision (benefit)	(2.2)	0.6	3.6
Net income (loss)	(4.0)	1.0	6.3
Net income attributable to non-controlling interest	(0.3)	—	(1.4)
Net income (loss) including non-controlling interest	$ (4.3)	$ 1.0	$ 4.9

The following table presents the main classes of assets and liabilities associated with the Partnership's discontinued operations at December 31, 2013. There were no assets and liabilities associated with discontinued operations at September 30, 2014:

	December 31, 2013
	(in millions)
Inventories	$ 0.2
Other current assets	0.2
Total current assets	0.4
Property, plant & equipment	72.3
Total assets	$ 72.7
Accounts payable	$ 3.2
Other current liabilities	1.1
Total current liabilities	4.3
Asset retirement obligations	7.1
Deferred income taxes	25.3
Other long-term liabilities	0.3
Total liabilities	$ 37.0

(16) Subsequent Events

E2 Drop Down. On October 22, 2014, the Partnership acquired from EnLink Midstream, Inc. (“EMI”), a wholly-owned subsidiary of ENLC,100% of the Class A Units and 50% of the Class B Units (collectively, the “E2 Appalachian Units”) in E2 Appalachian Compression, LLC (“E2 Appalachian”), and93.7% of the Class A Units (the “Energy Services Units” and, together with the E2 Appalachian Units, the “Purchased Units”) in E2 Energy Services, LLC (“Energy Services”). The total consideration paid by the Partnership to EMI for the Purchased Units included (i) $13.0 million in cash for the Energy Services Units and (ii) $150.0 million in cash and 1,016,322 common units representing limited partner interests in the Partnership for the E2 Appalachian Units. The remaining 50% of the Class B Units in E2 Appalachian are owned by members of the E2 Appalachian management team and are designed to provide such management team members with equity incentives. Pursuant to the limited liability company agreement of E2 Appalachian, such management owners will be required to sell their Class B Units to ENLK on either December 31, 2015 or March 31, 2016.

Acquisition of Natural Gas Pipeline Assets. Effective November 1, 2014, the Partnership acquired, through one of its wholly owned subsidiaries, Gulf Coast natural gas pipeline assets predominantly located in southern Louisiana for $235.0 million, subject to certain adjustments. The natural gas assets include natural gas pipelines spanning from Beaumont, Texas to the Mississippi River corridor and working natural gas storage capacity in southern Louisiana.

In September 2014, the Partnership paid the sellers, Chevron Pipe Line Company and Chevron Midstream Pipelines LLC, a $23.5 million deposit, which is included in "Other assets, net" on the condensed consolidated balance sheet.

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.

The historical financial statements included in this report reflect (1) for periods prior to March 7, 2014, the assets, liabilities and operations of EnLink Midstream Holdings, LP Predecessor (the "Predecessor"), the predecessor to EnLink Midstream Holdings, LP ("Midstream Holdings"), which is the historical predecessor of EnLink Midstream Partners, LP and (2) for periods on or after March 7, 2014, the results of operations of EnLink Midstream Partners, LP after giving effect to the business combination discussed under "Devon Energy Transaction" below . The Predecessor was comprised of all of the U.S. midstream assets and operations of Devon Energy Corporation ("Devon") prior to the business combination, including its 38.75% economic interest in Gulf Coast Fractionators ("GCF"). However, in connection with the business combination, only the Predecessor's systems serving the Barnett, Cana-Woodford and Arkoma-Woodford Shales in Texas and Oklahoma, as well as the economic burdens and benefits of the 38.75% economic interest in GCF, were contributed to Midstream Holdings, effective as of March 7, 2014.

You should read this discussion in conjunction with the historical financial statements and accompanying notes included in this report. All references in this section to the "Partnership", as well as the terms "our," "we," "us" and "its" (1) for periods prior to March 7, 2014 refer to the Predecessor and (2) for periods on or after March 7, 2014 refer to EnLink Midstream Partners, LP, together with its consolidated subsidiaries including the EnLink Midstream Operating, LP (formerly known as Crosstex Energy Services, L.P.) (the "Operating Partnership") and Midstream Holdings.

Overview

We are a Delaware limited partnership formed on July 12, 2002. We primarily focus on providing midstream energy services, including gathering, processing, transmission and marketing, to producers of natural gas, natural gas liquids ("NGLs") and crude oil. We also provide crude oil, condensate and brine disposal services to producers. Our midstream energy asset network includes approximately 8,800 miles of pipelines, thirteen natural gas processing plants, seven fractionators, 3.1 million barrels of NGL cavern storage, rail terminals, barge terminals, truck terminals and a fleet of approximately 100 trucks. We manage and report our activities primarily according to geography. We have five reportable segments: (1) Texas, which includes our activities in north Texas and the Permian Basin in west Texas; (2) Oklahoma, which includes our activities in Cana-Woodford and Arkoma-Woodford Shale areas; (3) Louisiana, which includes our pipelines, processing plants and NGL assets located in Louisiana; (4) ORV, which includes our activities in the Utica and Marcellus Shales; and (5) Corporate Segment, or Corporate, which includes our equity investments in Howard Energy Partners, or HEP, in the Eagle Ford Shale, our contractual right to the burdens and benefits associated with Devon's ownership interest in GCF in south Texas and our general partnership property and expenses.

We manage our operations by focusing on gross operating margin because our business is generally to purchase and resell natural gas, NGLs and crude oil for a margin or to gather, process, transport or market natural gas, NGLs and crude oil for a fee. In addition, we earn a volume based fee for providing crude oil transportation and brine disposal services. We define gross operating margin as operating revenue minus cost of purchased gas, NGLs, condensate and crude oil. Gross operating margin is a non-generally accepted accounting principle, or non-GAAP, financial measure and is explained in greater detail under "Non-GAAP Financial Measures" below.

Our gross operating margins are determined primarily by the volumes of natural gas gathered, transported, purchased and sold through our pipeline systems, processed at our processing facilities, the volumes of NGLs handled at our fractionation facilities, the volumes of crude oil handled at our crude terminals, the volumes of crude oil gathered, transported, purchased and sold and the volume of brine disposed. We generate revenues from seven primary sources:

- purchasing and reselling or transporting natural gas and NGLs on the pipeline systems we own;
- processing natural gas at our processing plants;
- fractionating and marketing the recovered NGLs;
- providing compression services;
- purchasing and reselling crude oil and condensate;
- providing crude oil and condensate transportation and terminal services; and

- providing brine transportation and disposal services.

We generally gather or transport gas owned by others through our facilities for a fee, or we buy natural gas from a producer, plant or shipper at either a fixed discount to a market index or a percentage of the market index, then transport and resell the natural gas at the market index. We attempt to execute all purchases and sales substantially concurrently, or we enter into a future delivery obligation, thereby establishing the basis for the margin we will receive for each natural gas transaction. Our gathering and transportation margins related to a percentage of the index price can be adversely affected by declines in the price of natural gas. We are also party to certain long-term gas sales commitments that we satisfy through supplies purchased under long-term gas purchase agreements. When we enter into those arrangements, our sales obligations generally match our purchase obligations. However, over time the supplies that we have under contract may decline due to reduced drilling or other causes and we may be required to satisfy the sales obligations by buying additional gas at prices that may exceed the prices received under the sales commitments. In our purchase/sale transactions, the resale price is generally based on the same index at which the gas was purchased. However, 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 margin. Changes in the basis spread can increase or decrease our margins.

The Partnership has made commitments to purchase natural gas in production areas based on production-area indices and to sell the natural gas into market areas based on market-area indices, pay the costs to transport the natural gas between the two points and capture the difference between the indices as margin. Changes in the index prices relative to each other (also referred to as basis spread) can significantly affect the Partnership's margins or even result in losses. For example, the Partnership is a party to one contract with a term to 2019 to supply approximately 150,000 MMBtu/d of gas. The Partnership buys gas for this contract on several different production-area indices on its North Texas Pipeline and sells the gas into a different market area index. The Partnership realizes a loss on the delivery of gas under this contract each month based on current prices. The balance sheet as of September 30, 2014 reflects a liability of $85.2 million related to this onerous performance obligation based on forecasted discounted cash obligations in excess of market under this gas delivery contract. Reduced supplies and 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 generally gather or transport crude oil and condensate owned by others by rail, truck, pipeline and barge facilities for a fee, or we 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 market index. We execute all purchases and sales substantially concurrently, thereby establishing the basis for the margin we will receive for each crude oil and condensate transaction. Additionally, we provide crude oil, condensate and brine services on a volume basis.

We also realize gross operating margins from our processing services primarily through three different contract arrangements: processing margins ("margin"), percentage of liquids ("POL") 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. 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 decrease or increase significantly in the short term with decreases or increases in the volume of gas, liquids, crude oil and condensate moved through or by the asset.

Our general and administrative expenses are dictated by the terms of our partnership agreement. These expenses include the costs of employee, officer and director compensation and benefits properly allocable to us, fees, services and other transaction costs related to acquisitions, and all other expenses necessary or appropriate to the conduct of business and allocable to us. Our partnership agreement provides that our General Partner determines the expenses that are allocable to us in any reasonable manner determined by our General Partner in its sole discretion.

Devon Energy Transaction

On March 7, 2014, the Partnership consummated the transactions contemplated by the Contribution Agreement, dated as of October 21, 2013 (the "Contribution Agreement"), among the Partnership, the Operating Partnership, Devon Energy Corporation ("Devon"), Devon Gas Corporation, Devon Gas Services, L.P. ("Gas Services") and Southwestern Gas Pipeline, Inc. ("Southwestern Gas" and, together with Gas Services, the "Contributors") pursuant to which the Contributors contributed (the "Contribution") to the Operating Partnership a 50% limited partner interest in Midstream Holdings and all of the outstanding equity interests in EnLink Midstream Holdings GP, LLC, the general partner of Midstream Holdings ("Midstream Holdings GP" and, together with Midstream Holdings and their subsidiaries, the "Midstream Group Entities"), in exchange for the issuance by the Partnership of 120,542,441 units representing a new class of limited partnership interests in the Partnership (the "Class B Units"). The Partnership owns midstream assets previously held by Devon in the Barnett Shale in North Texas, the Cana-Woodford and Arkoma-Woodford Shales in Oklahoma and a contractual right to the benefits and burdens associated with Devon's 38.75% interest in GCF in Mt. Belvieu, Texas. These assets consist of natural gas gathering and transportation systems, natural gas processing facilities and NGL fractionation facilities located in Texas and Oklahoma. Midstream Holdings' primary assets consist of three processing facilities with 1.3 Bcf/d of natural gas processing capacity, approximately 3,685 miles of pipelines with aggregate capacity of 2.9 Bcf/d and fractionation facilities with up to 160 MBbls/d of aggregate NGL fractionation capacity.

The Partnership units held by Devon represent approximately 52% of the outstanding limited partner interests in the Partnership, with approximately 40% of the outstanding limited partner interests held by the Partnership's public unitholders and approximately 7% of the outstanding limited partner interests, the approximate 1% general partner interest and the incentive distribution rights held indirectly by EnLink Midstream, LLC ("ENLC"). The Class B Units were substantially similar in all respects to the Partnership's common units representing limited partnership interests in the Partnership ("Common Units"), except that they were only entitled to a pro rata distribution for the fiscal quarter ended March 31, 2014. The Class B Units automatically converted into Common Units on a one-for-one basis on May 6, 2014.

Also on March 7, 2014, EnLink Midstream, Inc. (formerly known as Crosstex Energy, Inc.) (the "Corporation") and Devon consummated the transactions contemplated by the Merger Agreement, dated as of October 21, 2013 (the "Merger Agreement"), among the Corporation, Devon, ENLC, Acacia Natural Gas Corp I, Inc., formerly a wholly-owned subsidiary of Devon ("New Acacia"), and certain other wholly-owned subsidiaries of Devon pursuant to which the Corporation and New Acacia each became wholly-owned subsidiaries of ENLC (collectively, the "Mergers" and together with the Contribution, the "business combination"). As a result of the merger with New Acacia, ENLC indirectly owns the remaining 50% limited partner interest in Midstream Holdings.

Recent Developments

E2 Drop Down. On October 22, 2014, the Partnership acquired from EnLink Midstream, Inc. ("EMI"), a wholly-owned subsidiary of ENLC, 100% of the Class A Units and 50% of the Class B Units (collectively, the "E2 Appalachian Units") in E2 Appalachian Compression, LLC ("E2 Appalachian"), and 93.7% of the Class A Units (the "Energy Services Units" and, together with the E2 Appalachian Units, the "Purchased Units") in E2 Energy Services, LLC ("Energy Services"). The total consideration paid by the Partnership to EMI for the Purchased Units included (i) $13.0 million in cash for the Energy Services Units and (ii) $150.0 million in cash and 1,016,322 common units representing limited partner interests in the Partnership for the E2 Appalachian Units. The remaining 50% of the Class B Units in E2 Appalachian are owned by members of the E2 Appalachian management team and are designed to provide such management team members with equity incentives. Pursuant to the limited liability company agreement of E2 Appalachian, such management owners will be required to sell their Class B Units to ENLK on either December 31, 2015 or March 31, 2016.

E2's assets include five condensate stabilization and natural gas compression stations with combined capacities of 19,000 barrels per day ("bpd") of condensate stabilization and 580 MMcf/d of natural gas compression located in the Ohio River Valley. Currently, three of the five stations are in service and commercial start-up of the two remaining stations is expected in the first half of 2015. The assets are supported by a long-term, fee-based contract with Antero Resources.

Acquisition of Natural Gas Pipeline Assets. On November 1, 2014, we acquired Gulf Coast natural gas pipeline assets predominantly located in southern Louisiana, for $235.0 million, subject to certain adjustments. These natural gas pipeline assets include the following:

- **Bridgeline System:** approximately 985 miles of natural gas pipelines in southern Louisiana with a total system capacity of approximately 920 MMcf/d;
- **Sabine Pipeline:** approximately 150 miles of natural gas pipelines in Texas and southern Louisiana with a total capacity of approximately 235 MMcf/d;
- **Chandeleur System:** approximately 215 miles of offshore Mississippi and Alabama pipelines with a total capacity of approximately 330 MMcf/d;

- **Storage Assets:** three caverns located in southern Louisiana with a combined working capacity of approximately 11 Bcf, including two near Sorrento, LA with a capacity of approximately 4 Bcf and one inactive cavern near Napoleonville, LA with approximately 7 Bcf of capacity; and
- **Henry Hub:** ownership and management of the title tracking services offered at the Henry Hub, the delivery location for NYMEX natural gas futures contracts. Henry Hub is connected to 13 major interstate and intrastate natural gas pipeline and storage systems.

Ohio River Valley Condensate Pipeline and Condensate Stabilization Facilities. In August 2014, we announced plans to construct a new 45-mile, eight inch condensate pipeline and six natural gas compression and condensate stabilization facilities that will service major producer customers in the Utica Shale, including Eclipse Resources. As a component of the project, the Partnership has entered into a long-term, fee-based agreement under which Eclipse Resources will receive compression and stabilization services and has agreed to sell stabilized condensate to us.

The new-build stabilized condensate pipeline will connect to our existing 200-mile pipeline in eastern Ohio, providing producer customers in the region access to premium market outlets through our barge facility on the Ohio river and rail terminal in Ohio. The pipeline, which is expected to be complete in the second half of 2015, will have an initial capacity of approximately 50,000 bpd.

We will also build and operate six natural gas compression and condensate stabilization facilities in Noble, Belmont, and Guernsey counties in Ohio. Upon completion, the facilities will have a combined capacity of approximately 560 MMcf/d of natural gas compression and approximately 41,500 bpd of condensate stabilization. We expect the first two compression and condensate stabilization facilities to be operational in the second half of 2014 and the remaining four facilities to be operational by the end of 2015.

In support of the project, we plan to leverage and expand our existing midstream assets in the region, including increasing condensate storage capacity and handling capabilities at our barge terminal on the Ohio River. We will add approximately 130,000 barrels of above ground storage, bringing our total storage capacity at the barge facility to over 360,000 barrels.

West Texas Expansion. We will expand our natural gas gathering and processing system in the Permian Basin by constructing a new natural gas processing plant and expanding our rich gas gathering system. The new 120 MMcf/d gas processing plant will be strategically located on the north end of our existing midstream assets and will offer additional gas processing capabilities to producer customers in the region, including Devon Energy. The processing plant is expected to be operational in the second half of 2015. Upon completion, our total operated processing capacity in the region will be approximately 240 MMcf/d.

As a part of the expansion, we have signed a long-term, fee-based agreement with Devon Energy to provide gathering and processing services for over 18,000 acres under development in Martin County. We will construct multiple low pressure gathering pipelines and a new 23-mile, 12-inch high pressure gathering pipeline that will tie into the previously announced Bearkat natural gas gathering system. The new pipelines are expected to be operational in the first quarter of 2015.

Marathon Petroleum Joint Venture. We have entered into a series of agreements with a subsidiary of Marathon Petroleum Corporation to create a 50/50 joint venture named Ascension Pipeline Company, LLC. This joint venture will build a new 30-mile NGL pipeline connecting our existing Riverside fractionation and terminal complex to Marathon Petroleum's Garyville refinery located on the Mississippi River. The bolt-on project to our Cajun-Sibon NGL system is supported by long-term, fee-based contracts with Marathon Petroleum. Under the arrangement, we will serve as the construction manager and operator of the pipeline project, which is expected to be operational in the first half of 2017.

Cajun-Sibon Phases I and II. In Louisiana, we are transforming our business that historically has been focused on processing offshore natural gas to a business that is focused on NGLs with additional opportunities for growth from new onshore supplies of NGLs. The Louisiana petrochemical market historically has relied on liquids from offshore production; however, the decrease in offshore production and increase in onshore rich gas production have changed the market structure. Cajun-Sibon Phases I and II will work to bridge the gap between supply, which aggregates in the Mont Belvieu area, and demand, located in the Mississippi River corridor of Louisiana, thereby building a strategic NGL position in this region.

The pipeline expansion and the Eunice fractionation expansion under Phase I were completed and commenced operation in November 2013. Phase II of the Cajun Sibon expansion was completed and commenced operation in September 2014. Phase II increased the Cajun-Sibon pipeline capacity by an additional 50,000 Bbls/d to a total of 120,000 Bbls/d and added a new 100,000 Bbl/d fractionator at our Plaquemine gas processing complex. The throughput through the pipeline averaged 50,000 Bbls/d during the third quarter of 2014 due to downtime related to the start-up of Phase II. The Eunice fractionator in south Louisiana averaged approximately 43,000 Bbls/d during the third quarter of 2014. Additionally, our Riverside fractionator resumed service in September 2014 after being shut-down in July 2014 for the conversion of the facility to a heavy end fractionator as part of Phase II.

We believe the Cajun-Sibon project not only represents a tremendous growth step by leveraging our Louisiana assets, but that it also creates a significant platform for continued growth of our NGL business. We believe this project, along with our existing assets, will provide a number of additional opportunities to grow this business, including expanding market optionality and connectivity, upgrading products, expanding rail imports, exporting NGLs and expanding fractionation and product storage capacity.

Bearkat Natural Gas Gathering and Processing System. In September 2014, we completed construction of a new natural gas processing complex and rich gas gathering pipeline system in the Permian Basin called Bearkat. The natural gas processing complex includes treating, processing and gas takeaway solutions for regional producers. The project, which is fully owned by us, is supported by a 10-year, fee-based contract.

Bearkat is strategically located near our existing Deadwood joint venture assets in Glasscock County, Texas. The processing plant has an initial capacity of 60 MMcf/d, increasing our total operated processing capacity in the Permian to approximately 115 MMcf/d. We also completed construction on a 30-mile high-pressure gathering system upstream of the Bearkat complex to provide additional gathering capacity for producers in Glasscock and Reagan counties.

Additionally, in February 2014, we entered into an agreement to construct a new 35-mile, 12-inch diameter high-pressure pipeline that will provide critical gathering capacity for the Bearkat natural gas processing complex. The pipeline will have an initial capacity of approximately 100 MMcf/d and will provide gas takeaway solutions for constrained producer customers in Howard, Martin and Glasscock counties. The pipeline is expected to be operational in the fourth quarter of 2014.

Issuance of Common Units. In May 2014, we entered into an Equity Distribution Agreement (the “EDA”) with BMO Capital Markets Corp. (“BMOCM”). Pursuant to the terms of the EDA, we may from time to time through BMOCM, as our sales agent, sell common units representing limited partner interests having an aggregate offering price of up to $75.0 million.

Through September 30, 2014, we sold an aggregate of 2.4 million common units under the EDA, generating proceeds of approximately $72.0 million (net of approximately $0.7 million of commissions to BMOCM). We used the net proceeds for general partnership purposes, including working capital, capital expenditures and repayments of indebtedness.

Senior Unsecured Notes. On March 12, 2014, we commenced a tender offer to purchase any and all of our outstanding 8.875% Senior Notes due 2018 (the "2018 Notes"). Approximately $536.1 million, or approximately 74%, of the 2018 Notes were validly tendered on March 19, 2014, we made a payment of approximately $567.4 million for all such tendered 2018 Notes. Also on March 19, 2014, we delivered a notice of redemption for any and all outstanding 2018 Notes. The redemption for the remaining $198.2 million of outstanding 2018 Notes was completed on April 18, 2014 for $200.2 million, including accrued interest.

On July 22, 2014, we redeemed $18.5 million in aggregate principal amount of 7.125% senior unsecured notes (the “2022 Notes”) due on June 1, 2022 for $20.0 million, including accrued interest. On September 20, 2014, the Partnership redeemed an additional $15.5 million aggregate principal amount of the 2022 Notes for $17.0 million, including accrued interest.

Non-GAAP Financial Measures

We include the following non-GAAP financial measures: Adjusted earnings before interest, taxes, depreciation and amortization, or adjusted EBITDA, and gross operating margin.

We define adjusted EBITDA as net income from continuing operations plus interest expense, provision for income taxes, depreciation and amortization expense, stock-based compensation, (gain) loss on noncash derivatives, transaction costs, distribution of equity investment and non-controlling interest and income (loss) on equity investment. Adjusted EBITDA is used as a supplemental performance measure by our management and by external users of our financial statements, such as investors, commercial banks, research analysts and others, to assess:

- financial performance of our assets without regard to financing methods, capital structure or historical cost basis;
- the ability of our assets to generate cash sufficient to pay interest costs, support our indebtedness and make cash distributions to our unitholders and our General Partner;
- our operating performance and return on capital as compared to those of other companies in the midstream energy sector, without regard to financing methods or capital structure; and

- the viability of acquisitions and capital expenditure projects and the overall rates of return on alternative investment opportunities.

Adjusted EBITDA is a critical input into the financial covenant within our credit facility. The calculation of this ratio allows for further adjustments to adjusted EBITDA for recent material projects and acquisitions and dispositions.

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

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

The following tables reconcile adjusted EBITDA to the most directly comparable GAAP measure for the periods indicated.

Reconciliation of net income from continuing operations to adjusted EBITDA

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
	(in millions)			
Net income from continuing operations	$ 85.7	$ 34.6	$ 223.3	$ 87.6
Interest expense	12.7	—	30.5	—
Depreciation and amortization	71.6	48.0	192.3	138.6
Income from equity investment	(5.6)	(5.8)	(14.3)	(10.2)
Distribution from equity investment	8.2	12.0	13.9	12.0
Unit-based compensation	5.7	3.5	15.5	10.1
Income taxes	(0.1)	19.3	20.7	49.2
Gain on extinguishment of debt	(2.4)	—	(3.2)	—
Payments under onerous performance obligation offset to other current and long-term liabilities	(4.5)	—	(10.2)	—
Other (a)	(0.8)	—	2.3	0.2
Adjusted EBITDA before non-controlling interest	170.5	111.6	470.8	287.5
Non-controlling interest share of adjusted EBITDA	(59.2)	—	(132.4)	—
Adjusted EBITDA, net to EnLink Midstream Partners, LP	$ 111.3	$ 111.6	$ 338.4	$ 287.5

(a) Includes financial derivatives marked-to-market, accretion expense associated with asset retirement obligations and transaction costs related to the merger.

Reconciliation of net cash provided by operating activities to Adjusted EBITDA

	Three Months Ended September 30, 2014	Three Months Ended September 30, 2013	Nine Months Ended September 30, 2014	Nine Months Ended September 30, 2013
	(in millions)			
Net cash provided by operating activities	$ 160.7	$ 95.5	$ 385.4	$ 245.0
Interest expense, net (1)	13.3	—	31.6	—
Unit-based compensation (2)	—	3.5	2.8	10.1
Current income tax (benefit)	(0.5)	3.8	0.3	38.4
Distributions from equity investment in excess of earnings	2.6	1.1	7.6	1.1
Other (3)	0.8	—	1.7	—
Changes in operating assets and liabilities which provided cash:				
Accounts receivable, accrued revenues, inventories and other	(26.1)	5.3	(16.0)	1.1
Accounts payable, accrued purchases and other (4)	19.7	2.4	57.4	(8.2)
Adjusted EBITDA before non-controlling interest	170.5	111.6	470.8	287.5
Non-controlling interest share of adjusted EBITDA	(59.2)	—	(132.4)	—
Adjusted EBITDA, net to EnLink Midstream Partners, LP	$ 111.3	$ 111.6	$ 338.4	$ 287.5

(1) Net of amortization of debt issuance costs and discount and premium included in interest expense.

(2) Represents Predecessor stock-based compensation contributed through equity and reflected in net distributions to Predecessor in cash flows from financing activities in the Consolidated Statements of Cash Flows.

(3) Includes transaction costs.

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

We define gross operating margin, generally, as revenues less cost of purchased gas, NGLs, condensate and crude oil. 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 our business is generally to purchase and resell natural gas and crude oil for a margin or to gather, process, transport or market natural gas, NGLs and crude oil for a fee. Operating expense is a separate measure used by 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. As an indicator of our operating performance, gross operating margin should not be considered an alternative to, or more meaningful than, net income as determined in accordance with GAAP. Our gross operating margin may not be comparable to similarly titled measures of other companies because other entities may not calculate these amounts in the same manner.

The following table provides a reconciliation of gross operating margin to operating income:

	Three Months Ended September 30, 2014	Three Months Ended September 30, 2013	Nine Months Ended September 30, 2014	Nine Months Ended September 30, 2013
	(in millions)			
Total gross operating margin	$ 254.2	$ 142.7	$ 700.0	$ 413.5
Add (deduct):				
Operating expenses	(75.8)	(35.8)	(193.3)	(116.0)
General and administrative expenses	(22.8)	(10.8)	(62.8)	(32.3)
Depreciation and amortization	(71.6)	(48.0)	(192.3)	(138.6)
Gain on litigation settlement	6.1	—	6.1	—
Operating income	$ 90.1	$ 48.1	$ 257.7	$ 126.6

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 operating revenue less cost of purchased gas, NGLs, condensate and crude oil as reflected in the table below.

Items Affecting Comparability of Our Financial Results

Our historical financial results discussed below may not be comparable to our future financial results, and our financial results for the three and nine months ended September 30, 2013 may not be comparable to our financial results for the three and nine months ended September 30, 2014 for the following reasons:

- In connection with the business combination, Midstream Holdings entered into new agreements with Devon that were effective on March 1, 2014 pursuant to which Midstream Holdings provides services to Devon under fixed-fee arrangements in which Midstream Holdings does not take title to the natural gas gathered or processed or the NGLs it fractionates. Prior to the effectiveness of these agreements, the Predecessor provided services to Devon under a percent-of-proceeds arrangement in which it took title to the natural gas it gathered and processed and the NGLs it fractionated.

- Prior to March 7, 2014, our financial results only included the assets, liabilities and operations of our Predecessor. Beginning on March 7, 2014, our financial results also consolidate the assets, liabilities and operations of the legacy business of the Partnership prior to giving effect to the business combination.

- Subsequent to March 7, 2014, we owned a 50% interest in Midstream Holdings rather than the 100% ownership reflected as part of our Predecessor's historical financial results. We control Midstream Holdings through our ownership of its general partner. Our financial statements after March 7, 2014 consolidate all of Midstream Holdings' financial results with ours in accordance with GAAP and ENLC's 50% interest in Midstream Holdings is reflected as a non-controlling interest.

- Our financial statements for the three and nine months ended September 30, 2014 report financial results according to operating segments based principally upon geographic regions served. The Predecessor had no operations for certain of those reporting segments.

- All historical affiliated transactions prior to March 7, 2014 related to our continuing operations were net settled within our combined financial statements because these transactions related to Devon and were funded by Devon's working capital. Beginning on March 7, 2014, all our transactions are funded by our working capital. This will impact the comparability of our cash flow statements, working capital analysis and liquidity discussion.

- The Predecessor's historical assets comprised all of Devon's U.S.-midstream assets and operations. However, only its assets serving the Barnett, Cana-Woodford and Arkoma-Woodford Shales, as well as a contractual right to the burdens and benefits of its 38.75% interest in GCF, were contributed to Midstream Holdings in connection with the consummation of the business combination. Assets that were not contributed to Midstream Holdings are included in discontinued operations.

- The Predecessor's historical combined financial statements include U.S. federal and state income tax expense. Due to Midstream Holdings' status as a partnership, Midstream Holdings will not be subject to U.S. federal income tax or certain state income taxes in the future.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
	(in millions, except volumes)			
Texas Segment				
Revenues	$ 226.2	$ 392.3	$ 852.0	$ 1,148.9
Purchased gas and NGLs	(76.8)	(286.2)	(423.0)	(838.7)
Total gross operating margin	$ 149.4	$ 106.1	$ 429.0	$ 310.2
Louisiana Segment				
Revenues	$ 530.8	$ —	$ 1,263.6	$ —
Purchased gas, NGLs and crude oil	(486.9)	—	(1,158.2)	—
Total gross operating margin	$ 43.9	$ —	$ 105.4	$ —
Oklahoma Segment				
Revenues	$ 45.9	$ 185.9	$ 267.5	$ 544.2
Purchased gas and NGLs	—	(149.3)	(133.8)	(440.9)
Total gross operating margin	$ 45.9	$ 36.6	$ 133.7	$ 103.3
ORV Segment				
Revenues	$ 75.5	$ —	$ 180.2	$ —
Purchased crude oil and condensate	(61.5)	—	(146.4)	—
Total gross operating margin	$ 14.0	$ —	$ 33.8	$ —
Corporate				
Revenues	$ (27.0)	$ —	$ (65.3)	$ —
Purchased gas and NGLs	28.0	—	63.4	—
Total gross operating margin	$ 1.0	$ —	$ (1.9)	$ —
Total				
Revenues	$ 851.4	$ 578.2	$ 2,498.0	$ 1,693.1
Purchased gas, NGLs, condensate and crude oil	(597.2)	(435.5)	(1,798.0)	(1,279.6)
Total gross operating margin	$ 254.2	$ 142.7	$ 700.0	$ 413.5
Midstream Volumes:				
Texas (1)				
Gathering and Transportation (MMBtu/d)	2,975,600	2,086,000	2,979,000	2,112,000
Processing (MMBtu/d)	1,152,400	831,000	1,149,100	807,000
Louisiana (2)				
Gathering and Transportation (MMBtu/d)	500,200	—	459,300	—
Processing (MMBtu/d)	499,100	—	557,000	—
NGL Fractionation (Gals/d)	4,073,500	—	4,112,500	—
Oklahoma (3)				
Gathering and Transportation (MMBtu/d)	494,200	387,000	472,000	384,000
Processing (MMBtu/d)	447,300	407,000	448,300	393,000
ORV (2)				
Crude Oil Handling (Bbls/d)	15,200	—	15,400	—
Brine Disposal (Bbls/d)	5,000	—	5,300	—

(1) Volumes include volumes per day based on 92 days and 273 day periods for the three and nine months ended September 30, 2014, for Midstream Holdings operations. Volumes include volumes per day based on 92 days for the three months ended September 30, 2014 and volumes based on the 208 day period from March 7 to September 30, 2014 for the nine months ended September 30, 2014 for the Partnership's legacy operations in Texas.

(2) Volumes include volumes per day based on 92 days for the three months ended September 30, 2014 and based on the 208 day period from March 7 toSeptember 30, 2014 for the nine months ended September 30, 2014 for the Partnership's legacy operations. Midstream Holdings does not have any operations in Louisiana or Ohio.

(3) Volumes include volumes per day based on 92 and 273 day periods for the three and nine months ended September 30, 2014, respectively, for Midstream Holdings operations. The Partnership did not have any legacy operations in Oklahoma.

Three Months Ended September 30, 2014 Compared to Three Months Ended September 30, 2013

Gross Operating Margin. Gross operating margin was $254.2 million for the three months ended September 30, 2014 as compared to $142.7 million for the three months ended September 30, 2013, an increase of $111.5 million, or 78.1% Of this increase in gross operating margin, $99.4 million is attributable to the legacy Partnership assets associated with the business combination effective on March 7, 2014. Approximately $12.1 million of the increase in gross operating margin is related to Midstream Holdings, which is the result of the new fixed-fee arrangements with Devon entered into in connection with the business combination.

Operating Expenses. Operating expenses were $75.8 million for the three months ended September 30, 2014 as compared to $35.8 million for the three months ended September 30, 2013, an increase of $40.0 million, or 111.7%. Of this increase in operating expenses, $43.1 million is attributable to the legacy Partnership assets, partially offset by a decrease in Midstream Holdings' operating expenses of $3.1 million due to both lower personnel and contract labor expense and a decrease in compressor maintenance expense.

General and Administrative Expenses. General and administrative expenses were $22.8 million for the three months ended September 30, 2014 as compared to $10.8 million for the three months ended September 30, 2013, an increase of $12.0 million, or 111.1%. General and administrative expenses for the three months ended September 30, 2014 reflect expenses associated with the new combined operations of the legacy Partnership and Midstream Holdings, including $1.0 million for transition service costs from Devon. General and administrative expenses for the three months ended September 30, 2013 reflect expenses for Midstream Holdings which primarily consisted of costs allocated by Devon for shared general and administrative services.

Depreciation and Amortization. Depreciation and amortization expenses were $71.6 million for the three months ended September 30, 2014 as compared to $48.0 million for the three months ended September 30, 2013, an increase of $23.6 million, or 49.2%. The increase in depreciation and amortization expenses result from an increase in depreciation expense of $37.1 million related to the legacy Partnership assets acquired in March 2014. This increase was partially offset by a decrease of $13.6 million in depreciation and amortization expenses related to Midstream Holdings, with the primary driver being the change in depreciation methodology from the units-of-production method to the straight-line method of $9.3 million.

Gain on Litigation Settlement. We recognized a gain on the settlement of a lawsuit of $6.1 million for the three months ended September 30, 2014 due to a partial settlement of our claims against Texas Brine and its insurers. Additional claims related to this matter remain outstanding.

Interest Expense. Interest expense was $12.7 million for the three months ended September 30, 2014. There was no interest expense for thethree months ended September 30, 2013 as Midstream Holdings did not have any debt. Net interest expense consists of the following (in millions):

	Three Months Ended September 30, 2014
Senior notes	$ 15.8
Bank credit facility	1.7
Capitalized interest	(4.6)
Amortization of debt issue cost, discount and premium	(0.3)
Other	0.1
Total	$ 12.7

Income from Equity Investments. Income from equity investments was $5.6 million for the three months ended September 30, 2014 as compared to $5.8 million for the three months ended September 30, 2013, a decrease of $0.2 million. The decrease primarily relates to our investment in GCF due to a decrease in volumes.

Income Tax (Expense)Benefit. Income tax benefit was $0.1 million for the three months ended September 30, 2014 as compared to income tax expense of $19.3 million for the three months ended September 30, 2013, a decrease of $19.4 million. This decrease primarily relates to taxable income related to the Predecessor, which was a taxable entity prior to the business combination on March 7, 2014.

Net Income from Discontinued Operations. The Partnership had no net income from discontinued operations for the three months ended September 30, 2014 as compared to a net loss of $4.3 million for the three months ended September 30, 2013. Discontinued operations for the period ended September 30, 2013 included assets that were not contributed to Midstream Holdings, while Midstream Holdings had no discontinued operations during the period ended September 30, 2014.

Nine Months Ended September 30, 2014 Compared to Nine Months Ended September 30, 2013

Gross Operating Margin. Gross operating margin was $700.0 million for the nine months ended September 30, 2014 as compared to $413.5 million for the nine months ended September 30, 2013, an increase of $286.5 million, or 69.3%. Of this increase in gross operating margin, $230.6 million is attributable to the legacy Partnership assets associated with the business combination effective on March 7, 2014. Approximately $55.8 million of the increase in gross operating margin is related to Midstream Holdings, which is the result of the new fixed-fee arrangements with Devon entered into in connection with the business combination.

Operating Expenses. Operating expenses were $193.3 million for the nine months ended September 30, 2014 as compared to $116.0 million for the nine months ended September 30, 2013, an increase of $77.3 million, or 66.6%. Of this increase in operating expenses, $94.1 million is attributable to the legacy Partnership assets, partially offset by a decrease in Midstream Holdings' operating expenses of $16.7 million due to both lower personnel and contract labor expense and a decrease in compressor maintenance expense.

General and Administrative Expenses. General and administrative expenses were $62.8 million for the nine months ended September 30, 2014 compared to $32.3 million for the nine months ended September 30, 2013, an increase of $30.5 million, or 94.4%. General and administrative expenses for the nine months ended September 30, 2014 reflect expenses associated with the new combined operations of the legacy Partnership and Midstream Holdings since March 7, 2014, including $2.3 million for transition service costs from Devon, together with general and administrative expenses of Midstream Holdings prior to March 7, 2014. General and administrative expenses for the nine months ended September 30, 2013 reflect expenses for Midstream Holdings which primarily consisted of costs allocated by Devon for shared general and administrative services.

Depreciation and Amortization. Depreciation and amortization expenses were $192.3 million for the nine months ended September 30, 2014 compared to $138.6 million for the nine months ended September 30, 2013, an increase of $53.7 million, or 38.7%. The increase in depreciation and amortization expenses result from an increase in depreciation expense of $84.6 million related to the legacy Partnership assets acquired in March 2014. The increase was partially offset by a decrease of $30.9 million in depreciation and amortization expenses related to Midstream Holdings with the primary driver being the change in depreciation methodology from the units-of-production method to the straight-line method of $21.0 million. The remaining decrease related to a $5.6 million decrease due to a change in the annual units of production rate partially offset by a $1.7 million increase related to assets placed in service during 2013.

Gain on Litigation Settlement. We recognized a gain on the settlement of a lawsuit of $6.1 million for the nine months ended September 30, 2014 due to a partial settlement of our claims against Texas Brine and its insurers. Additional claims related to this matter remain outstanding.

Interest Expense. Interest expense was $30.5 million for the nine months ended September 30, 2014. There was no interest expense for the nine months ended September 30, 2013 as the Predecessor did not have any debt. Net interest expense consists of the following (in millions):

	Nine Months Ended September 30, 2014
Senior notes	$ 37.5
Bank credit facility	3.1
Capitalized interest	(9.9)
Amortization of debt issue cost, discount and premium	(1.0)
Other	0.8
Total	$ 30.5

Income from Equity Investments. Income from equity investments was $14.3 million for the nine months ended September 30, 2014 as compared to $10.2 million for the nine months ended September 30, 2013, an increase of $4.1 million. The increase primarily relates to our investment in GCF due to turnaround downtime experienced during the 2013 period.

Income Tax Expense. Income tax expense was $20.7 million for the nine months ended September 30, 2014 as compared to $49.2 million for the nine months ended September 30, 2013, a decrease of $28.5 million or 57.9%. This decrease primarily relates to taxable income related to the Predecessor, which was a taxable entity prior to the business combination on March 7, 2014.

Net Income from Discontinued Operations. Net income from discontinued operations was $1.0 million for the nine months ended September 30, 2014 as compared to $4.9 million for the nine months ended September 30, 2013, a decrease of $3.9 million. The decrease is due to Midstream Holdings' discontinued operations for the period ended September 30, 2013 which included assets that were sold during 2013, while the nine month period ended September 30, 2014 includes Predecessor assets that were not contributed to Midstream Holdings as part of the business combination.

Supplemental Information

As a supplement to the financial information included herein for the three and nine months ended September 30, 2014, the Partnership is furnishing the following tables, which segregate the results of operations of Midstream Holdings from the Partnership's other operations. The tables below reflect the following for the three and nine months ended September 30, 2014:

- the Partnership's results of operations excluding the operations of Midstream Holdings;
- the results of operations of 100% of Midstream Holdings on a stand-alone basis;
- the elimination of the 50% of the net income of Midstream Holdings attributable to the non-controlling interest in Midstream Holdings held by ENLC;
- the Predecessor's results of operations for the period January 1, 2014 through March 6, 2014; and
- the Partnership's results of operations on a consolidated basis.

	Three Months Ended September 30, 2014			
	Partnership Excluding Midstream Holdings	Midstream Holdings	Eliminations	Partnership Consolidated
	(in millions)			
Revenues:				
Revenues	$ 644.1	$ —	$ —	$ 644.1
Revenues - affiliates	51.5	154.8	—	206.3
Loss on derivative activity	1.0	—	—	1.0
Total revenues	696.6	154.8	—	851.4
Operating costs and expenses:				
Purchased gas, NGLs, condensate and crude oil	597.2	—	—	597.2
Operating expenses	43.0	32.8	—	75.8
General and administrative	14.0	8.8	—	22.8
Depreciation and amortization	37.2	34.4	—	71.6
Gain on litigation settlement	(6.1)	—	—	(6.1)
Total operating costs and expenses	685.3	76.0	—	761.3
Operating income (loss)	11.3	78.8	—	90.1
Other income (expense):				
Interest expense, net of interest income	(12.7)	—	—	(12.7)
Income from equity investments	0.4	5.2	—	5.6
Gain on extinguishment of debt	2.4	—	—	2.4
Other expense	0.2	—	—	0.2
Total other income (expense)	(9.7)	5.2	—	(4.5)
Income from continuing operations before non-controlling interest and income taxes	1.6	84.0	—	85.6
Income tax (provision) benefit	0.8	(0.7)	—	0.1
Net income	2.4	83.3	—	85.7
Net income attributable to the non-controlling interest	—	—	41.7	41.7
Net income attributable to EnLink Midstream Partners, LP	$ 2.4	$ 83.3	$ (41.7)	$ 44.0

	Nine Months Ended September 30, 2014				
	Predecessor	Partnership Excluding Midstream Holdings	Midstream Holdings	Eliminations	Partnership Consolidated
Revenues:					
Revenues	$ 47.3	$ 1,580.6	$ —	$ —	$ 1,627.9
Revenues - affiliates	436.4	81.5	354.1	—	872.0
Loss on derivative activity	—	(1.9)	—	—	(1.9)
Total revenues	483.7	1,660.2	354.1	—	2,498.0
Operating costs and expenses:					
Purchased gas, NGLs, condensate and crude oil	368.5	1,429.5	—	—	1,798.0
Operating expenses	23.7	95.7	73.9	—	193.3
General and administrative	10.9	31.4	20.5	—	62.8
Depreciation and amortization	28.9	84.7	78.7	—	192.3
Gain on litigation settlement	—	(6.1)	—	—	(6.1)
Total operating costs and expenses	432.0	1,635.2	173.1	—	2,240.3
Operating income	51.7	25.0	181.0	—	257.7
Other income (expense):					
Interest expense, net of interest income	—	(30.5)	—	—	(30.5)
Income from equity investments	2.3	1.8	10.2	—	14.3
Gain on extinguishment of debt	—	3.2	—	—	3.2
Other expense	—	(0.7)	—	—	(0.7)
Total other income (expense)	2.3	(26.2)	10.2	—	(13.7)
Income (loss) from continuing operations before non-controlling interest and income taxes	54.0	(1.2)	191.2	—	244.0
Income tax provision	(19.5)	0.2	(1.4)	—	(20.7)
Net income (loss) from continuing operations	34.5	(1.0)	189.8	—	223.3
Discontinued operations:					
Income from discontinued operations, net of tax	1.0	—	—	—	1.0
Income from discontinued operations attributable to non-controlling interest, net of tax	—	—	—	—	—
Discontinued operations, net of tax	1.0	—	—	—	1.0
Net income (loss)	35.5	(1.0)	189.8	—	224.3
Net income attributable to the non-controlling interest	—	—	—	94.8	94.8
Net income (loss) attributable to EnLink Midstream Partners, LP	$ 35.5	$ (1.0)	$ 189.8	$ (94.8)	$ 129.5

Critical Accounting Policies

The selection and application of accounting policies is an important process that has developed as our business activities have evolved and as the accounting rules have developed. Accounting rules generally do not involve a selection among alternatives, but involve an implementation and interpretation of existing rules, and the use of judgment to the specific set of circumstances existing in our business. Compliance with the rules necessarily involves reducing a number of very subjective judgments to a quantifiable accounting entry or valuation. We make every effort to properly comply with all applicable rules on or before their adoption, and we believe the proper implementation and consistent application of the accounting rules is critical.

Our critical accounting policies are discussed below. See Note 2 of the Notes to Consolidated Financial Statements for further details on our accounting policies.

Revenue Recognition and Commodity Risk Management. We recognize revenue for sales or services at the time the natural gas, NGLs or crude oil is delivered or at the time the service is performed. We generally accrue one month of sales and the related gas, NGL or crude oil purchases and reverse these accruals when the sales and purchases are actually invoiced and recorded in the subsequent months. Actual results could differ from the accrual estimates.

We utilize extensive estimation procedures to determine the sales and cost of gas, NGL or crude oil purchase accruals for each accounting cycle. Accruals are based on estimates of volumes flowing each month from a variety of sources. We use actual measurement data, if it is available, and will use such data as producer/shipper nominations, prior month average daily flows, estimated flow for new production and estimated end-user requirements (all adjusted for the estimated impact of weather patterns) when actual measurement data is not available. Throughout the month or two following production, actual measured sales and transportation volumes are received and invoiced and used in a process referred to as "actualization". Through the actualization process, any estimation differences recorded through the accrual are reflected in the subsequent month's accounting cycle when the accrual is reversed and actual amounts are recorded. Actual volumes purchased, processed or sold may differ from the estimates due to a variety of factors including, but not limited to: actual wellhead production or customer requirements being higher or lower than the amount nominated at the beginning of the month; liquids recoveries being higher or lower than estimated because gas processed through the plants was richer or leaner than estimated; the estimated impact of weather patterns being different from the actual impact on sales and purchases; and pipeline maintenance or allocation causing actual deliveries of gas to be different than estimated. We believe that our accrual process for sales and purchases provides a reasonable estimate of such sales and purchases.

We engage in price risk management activities in order to minimize the risk from market fluctuations in the price of natural gas, NGLs, crude oil and condensate. We also manage our price risk related to future physical purchase or sale commitments by entering into either corresponding physical delivery contracts or financial instruments with an objective to balance our future commitments and significantly reduce our risk to the movement in natural gas and NGL prices.

We use derivatives to hedge against changes in cash flows related to product prices, as opposed to their use for trading purposes. FASB ASC 815 requires that all derivatives and hedging instruments are recognized as assets or liabilities at fair value. If a derivative qualifies for hedge accounting, changes in the fair value can be offset against the change in the fair value of the hedged item through earnings or recognized in other comprehensive income until such time as the hedged item is recognized in earnings.

We manage our price risk related to future physical purchase or sale commitments for energy trading activities by entering into either corresponding physical delivery contracts or financial instruments with an objective to balance future commitments and significantly reduce risk related to the movement in natural gas prices. However, we are subject to counter-party risk for both the physical and financial contracts. Our energy trading contracts qualify as derivatives and we use mark-to-market accounting for both physical and financial contracts of the energy trading business. Accordingly, any gain or loss associated with changes in the fair value of derivatives and physical delivery contracts relating to energy trading activities are recognized currently in earnings as gain or loss on derivatives.

Impairment of Long-Lived Assets. In accordance with FASB ASC 360-10-05, we evaluate the long-lived assets, including related intangibles, of identifiable business activities for impairment when events or changes in circumstances indicate, in management's judgment, that the carrying value of such assets may not be recoverable. The determination of whether impairment has occurred is based on management's estimate of undiscounted future cash flows attributable to the assets as compared to the carrying value of the assets. If impairment has occurred, the amount of the impairment recognized is determined by estimating the fair value for the assets and recording a provision for loss if the carrying value is greater than fair value.

When determining whether impairment of one of our long-lived assets has occurred, we must estimate the undiscounted cash flows attributable to the asset. Our estimate of cash flows is based on assumptions regarding the purchase and resale margins on natural gas, volume of gas available to the asset, markets available to the asset, operating expenses, and future natural gas prices and NGL product prices. The amount of availability of gas and crude oil to an asset is sometimes based on assumptions regarding future drilling activity, which may be dependent in part on natural gas and crude oil prices. Projections of gas and crude oil volumes and future commodity prices are inherently subjective and contingent upon a number of variable factors, including but not limited to:

- changes in general economic conditions in regions in which our markets are located;

- the availability and prices of natural gas, crude oil and condensate supply;
- our ability to negotiate favorable sales agreements;
- the risks that natural gas, crude oil and condensate exploration and production activities will not occur or be successful;
- our dependence on certain significant customers, producers and transporters of natural gas, crude oil and condensate; and
- competition from other midstream companies, including major energy producers.

Any significant variance in any of the above assumptions or factors could materially affect our cash flows, which could require us to record an impairment of an asset.

Impairment of Goodwill. Goodwill is the cost of an acquisition less the fair value of the net identifiable assets of the acquired business. We will evaluate goodwill for impairment annually as of October 31st, 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 the two-step goodwill impairment test. We may elect to perform the two-step goodwill impairment test without completing a qualitative assessment. If a two-step process goodwill impairment test is elected or required, the first step involves comparing the fair value of the reporting unit, to which goodwill has been allocated, with its carrying amount. If the carrying amount of a reporting unit exceeds its fair value, the second step of the process involves 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 exceeds the implied fair value of that goodwill, the excess of the carrying value over the implied fair value is recognized as an impairment loss.

Depreciation Expense and Cost Capitalization. Our assets consist primarily of natural gas, NGL, condensate and crude oil gathering pipelines, processing plants, transmission pipelines and trucks. We capitalize all construction-related direct labor and material costs, as well as indirect construction costs. Indirect construction costs include general engineering and the costs of funds used in construction. Capitalized interest represents the cost of funds used to finance the construction of new facilities and is expensed over the life of the constructed assets through the recording of depreciation expense. We capitalize the costs of renewals and betterments that extend the useful life, while we expense the costs of repairs, replacements and maintenance projects as incurred.

Historically, Midstream Holdings depreciated certain property, plant, and equipment using the units-of-production method. As a result of the business combination, Midstream Holdings is operated as an independent midstream company and thus no longer has access to Devon's proprietary reserve and production data historically used to compute depreciation under the units-of-production method. Additionally, the existing contracts with Devon were revised to a fee-based arrangement with minimum volume commitments. Effective March 7, 2014, the Partnership changed its method of computing depreciation for these assets to the straight-line method, consistent with the depreciation method applied to the Partnership's legacy assets. In accordance with FASB ASC 250, the Partnership determined that the change in depreciation method is a change in accounting estimate, and accordingly, the straight-line method will be applied on a prospective basis. This change is considered preferable because the straight-line method more accurately reflects the pattern of usage and the expected benefits of such assets.

Certain assets such as land, NGL line pack, natural gas line pack and crude oil line pack are non-depreciable. The computation of depreciation expense requires judgment regarding the estimated useful lives and salvage value of assets. As circumstances warrant, we may review depreciation estimates to determine if any changes are needed. Such changes could involve an increase or decrease in estimated useful lives or salvage values, which would impact future depreciation expense.

Liquidity and Capital Resources

Cash Flows from Operating Activities. Net cash provided by operating activities was $385.4 million for the nine months ended September 30, 2014 compared to $245.0 million for the nine months ended September 30, 2013. Operating cash flows and changes in working capital for comparative periods were as follows (in millions):

	Nine Months Ended September 30,	
	2014	**2013**
Operating cash flows before working capital	$ 437.0	$ 238.0
Changes in working capital	$ (51.6)	$ 7.0

The primary reason for the increase in operating cash flows before working capital of $199.0 million from 2013 to 2014 relates to an increase in gross operating margin from the acquired legacy Partnership assets and Midstream Holdings assets. The decrease in working capital for 2014 related to fluctuations in trade receivable and payable balances due to timing of collection and payments and changes in inventory balances due to normal operating fluctuations. Further, prior to March 7, 2014, all cash receipts for the Predecessor were deposited into Devon's bank accounts, and all cash disbursements were made from these accounts. Cash transactions handled by Devon were reflected in intercompany advances between Devon and the Predecessor, all of which were settled through an adjustment to equity and reflected in cash flows from financing activities. Subsequent to March 7, 2014, Midstream Holdings handles all of its cash transactions and the changes in working capital are reflected in our cash flows from operating activities.

Cash Flows from Investing Activities. Net cash used in investing activities was $528.9 million for the nine months ended September 30, 2014 and $200.2 million for the nine months ended September 30, 2013. Our primary investing cash flows were acquisition costs and capital expenditures, net of accrued amounts, as follows (in millions):

	Nine Months Ended September 30, 2014	2013
Growth capital expenditures	$ 448.7	$ 149.0
Maintenance capital expenditures	23.4	52.3
Acquisition of business	35.2	—
Deposit for acquisition	23.5	—
Investment in equity investment company	5.7	—
Distribution from equity investment company in excess of earnings	(7.6)	(1.1)
Total	$ 528.9	$ 200.2

Cash Flows from Financing Activities. Net cash provided by financing activities was $167.6 million for the nine months ended September 30, 2014 and net cash used in financing activities was $117.7 million for the nine months ended September 30, 2013. All Predecessor financing activities from January 1, 2014 through March 6, 2014 and the nine months ended September 30, 2013 totaling $27.2 million and $117.7 million, respectively, are reflected in distributions to Predecessor on the statement of cash flows. Our primary financing activities subsequent to March 7, 2014 consist of the following (in millions):

	Nine Months Ended September 30, 2014
Net borrowings on bank credit facility	$ (6.0)
Senior unsecured notes borrowings	1,190.0
Redemption of 2018 Notes	(760.3)
Partial redemption of 2022 Notes	(36.4)
Net repayments under capital lease obligations	(2.1)
Debt refinancing costs	(6.4)
Proceeds from issuance of common units	71.9

Distributions to unitholders and our general partner also represent a primary use of cash in financing activities. Total cash distributions made during the nine months ended September 30, 2014 were as follows (in millions):

	Nine Months Ended September 30, 2014
Common units	$ 136.1
General partner interest (including incentive distribution rights)	10.2
Total	$ 146.3

Prior to the business combination, Midstream Holdings' continuing operations had no separate cash accounts. The owner contributions and distributions represent the net amount of all transactions that were settled with adjustments to equity. Midstream Holdings had distributions of $27.2 million to Devon for the nine months ended September 30, 2014 (relating to the period from January 1, 2014 to March 6, 2014) and distributions to Devon of $117.7 million for the nine months ended September 30, 2013. Also, Midstream Holdings made distributions of $106.9 million to ENLC for the nine months ended September 30, 2014 relating to ENLC's 50% ownership interest in Midstream Holdings.

In order to reduce our interest costs, we do not borrow money to fund outstanding checks until they are presented to the bank. Fluctuations in drafts payable are caused by timing of disbursements, cash receipts and draws on our credit facility. We borrow money under our credit facility to fund checks as they are presented. Change in drafts payable for the nine months ended September 30, 2014 was as follows (in millions):

	Nine Months Ended September 30, 2014
Decrease in drafts payable	$ (2.6)

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 these pipelines and underground storage reservoirs. This sinkhole is situated west of our underground natural gas and NGL storage facility. The cause of the sinkhole is currently under investigation by Louisiana state and local officials. We took a section of our 36-inch-diameter natural gas pipeline located near the sinkhole out of service. Service to certain markets, primarily in the Mississippi River area, has been curtailed or interrupted, and we have worked with our customers to secure alternative natural gas supplies so that disruptions are minimized. The replacement pipeline was completed and services resumed in May 2014.

We are assessing the potential for recovering our losses from responsible parties. We have sued Texas Brine, LLC, the operator of a failed cavern in the area, and its insurers seeking recovery for this damage. We also filed a claim with our insurers. Our insurers denied our claim. We dispute the denial but have agreed to stay the matter pending resolution of our claims against Texas Brine and its insurers. In August 2014, we received a partial settlement in the amount of $6.1 million. 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 one of our subsidiaries, EnLink Processing Services, LLC, as a defendant in a pending lawsuit they had filed against Texas Brine Company, LLC, Occidental Chemical Corporation, and Vulcan Materials Company relating to claims arising from the August 2012 sinkhole that formed in the Bayou Corne area of Assumption Parish, Louisiana. The suit is pending in the 23rd Judicial Court, Assumption Parish, Louisiana. Although plaintiffs' claims against the other defendants have been pending since October 2012, plaintiffs are now alleging that EnLink Processing Services, LLC's negligence also contributed to the formation of the sinkhole. The amount of damages is unspecified. The validity of the causes of action, as well as our costs and legal exposure, if any, related to the lawsuit are not currently determinable. We intend to vigorously defend the case. We have also filed a claim for defense and indemnity with its insurers.

Capital Requirements. During the nine months ended September 30, 2014, capital investments were $448.7 million, which were funded by internally generated cash flow and borrowings under our credit facility. Our remaining current growth capital spending projection for 2014 is approximately $550.0 million to $590.0 million related to identified growth projects, including approximately $212.0 million and $180.0 million for our acquisition of the natural gas assets in southern Louisiana and E2 acquisition, respectively. Our 2015 projected capital spend for growth capital is approximately $300.0 million to $400.0 million. We expect to fund the growth capital expenditures from the proceeds of borrowing under our bank credit facility and from other debt and equity sources.

Off-Balance Sheet Arrangements. No off-balance sheet arrangements existed as of September 30, 2014.

Total Contractual Cash Obligations. A summary of contractual cash obligations as of September 30, 2014 is as follows (in millions):

	Payments Due by Period						
	Total	Remainder 2014	2015	2016	2017	2018	Thereafter
Long-term debt obligations	$ 1,362.5	$ —	$ —	$ —	$ —	$ —	$ 1,362.5
Credit facility	371.0	—	—	—	—	—	371.0
Interest payable on fixed long-term debt obligations	934.3	32.5	61.8	61.8	61.8	61.8	654.6
Capital lease obligations	23.2	1.1	4.6	4.6	6.7	2.9	3.3
Operating lease obligations	50.9	3.4	11.4	8.8	5.6	6.0	15.7
Purchase obligations	15.8	15.8	—	—	—	—	—
Delivery contract obligation	85.2	4.5	17.9	17.9	17.9	17.9	9.1
Inactive easement commitment*	8.0	—	1.0	1.0	1.0	1.0	4.0
Uncertain tax position obligations	2.6	2.6	—	—	—	—	—
Total contractual obligations	$ 2,853.5	$ 59.9	$ 96.7	$ 94.1	$ 93.0	$ 89.6	$ 2,420.2

* Amounts related to inactive easements paid as utilized by the Partnership with balance due at end of 10 years if not utilized.

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 Partnership's 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 September 30, 2014, the cash obligation for interest expense on the Partnership's credit facility would be approximately $7.0 million per year or approximately $1.8 million for the remainder of 2014.

Indebtedness

As of September 30, 2014, long-term debt consisted of the following (in millions):

	September 30, 2014
Bank credit facility (due 2019), interest based on Prime and/or LIBOR plus an applicable margin, interest rate at September 30, 2014 was 1.9%	$ 371.0
Senior unsecured notes (due 2019), net of discount of $2.7 million, which bear interest at the rate of 2.70%	397.3
Senior unsecured notes (due 2022), including a premium of $22.6 million, which bear interest at the rate of 7.125%	185.1
Senior unsecured notes (due 2024), net of discount of $3.5 million, which bear interest at the rate of 4.40%	446.5
Senior unsecured notes (due 2044), net of discount of $3.3 million, which bear interest at the rate of 5.60%	346.8
Debt classified as long-term	$ 1,746.7

Credit Facility. As of September 30, 2014, there were $14.0 million in outstanding letters of credit and $371.0 million of outstanding borrowings under the Partnership's bank credit facility, leaving approximately $615.0 million available for future borrowing based on the borrowing capacity of $1.0 billion. The credit facility will mature on the fifth anniversary of the initial funding date, which was March 7, 2014, unless we request, and the requisite lenders agree, to extend it pursuant to its terms. See Note 5 to the condensed consolidated financial statements titled "Long-Term Debt" for further details.

Recent Accounting Pronouncements

We have reviewed all recently issued accounting pronouncements that became effective during the nine months ended September 30, 2014 and have determined that none would have a material impact to our Unaudited Condensed Consolidated Financial Statements.

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 which are not historical facts are forward-looking statements. These statements can be identified by the use of forward-looking terminology including “forecast,” “may,” “believe,” “will,” “expect,” “anticipate,” “estimate,” “continue” or other similar words. These statements discuss future expectations, contain projections of results of operations or of financial condition or state other “forward-looking” information. Such statements reflect our current views with respect to future events based on what we believe are reasonable assumptions; however, such statements are subject to certain risks and uncertainties. In addition to specific uncertainties discussed elsewhere in this 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 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. The legislation and new regulations may also require counterparties to our derivative instruments to spin off some of their derivatives activities to separate entities, which may not be as creditworthy as the current counterparties. The new legislation and any future new regulations could significantly increase the cost of derivative contracts, materially alter the terms of derivative contracts, reduce the availability of derivatives to protect against risks we encounter, reduce our ability to monetize or restructure our existing derivative contracts, and increase our exposure to less creditworthy counterparties. If we reduce our use of derivatives as a result of the legislation and regulations, our results of operations may become more volatile and our cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures and to generate sufficient cash flow to pay quarterly distributions at current levels or at all. Our revenues could be adversely affected if a consequence of the legislation and regulations is lower commodity prices. Any of these consequences could have a material, adverse effect on us, our financial condition and our results of operations.

Commodity Price Risk

We are subject to significant risks due to fluctuations in commodity prices. Our exposure to these risks is primarily in the gas processing component of our business. We currently process gas under three main types of contractual arrangements as summarized below. Approximately 89% of our processing margins are from fixed fee based contracts.

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

3. *Fee based contracts:* Under these contracts we have no 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 which 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.

The following table sets forth certain information related to derivative instruments outstanding at September 30, 2014 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 the Oil Price Information Service ("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 *	Fair Value Asset/(Liability) (In millions)
October 2014 - December 2016	Ethane	1,033	(MBbls)	Index	$0.2757/gal	$ (0.7)
October 2014 - December 2016	Propane	1,240	(MBbls)	Index	$1.0211/gal	0.3
October 2014 - May 2015	Normal Butane	63	(MBbls)	Index	$1.1994/gal	0.1
October 2014 - May 2015	Natural Gasoline	49	(MBbls)	Index	$1.9255/gal	0.1
October 2014 - May 2015	Natural Gas	2	(MMBtu/d)	$4.0963/MMBtu*	Index	—
						$ (0.2)

*weighted average

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

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

As of September 30, 2014, 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 $0.2 million. The aggregate effect of a hypothetical 10% change, increase or decrease, in gas and NGL prices would result in a change of approximately $5.2 million in the net fair value of these contracts as of September 30, 2014.

Interest Rate Risk

We are exposed to interest rate risk on our variable rate bank credit facility. At September 30, 2014, we had $371.0 million in outstanding borrowings under this facility. A 1% increase or decrease in interest rates would change our annual interest expense by approximately $3.7 million for the year.

We are not exposed to changes in interest rates with respect to our senior unsecured notes due in 2019, 2022, 2024 or 2044, as these obligations are fixed rates. The estimated fair value of our senior unsecured notes was approximately $1,438.2 million as of September 30, 2014, based on market prices of similar debt atSeptember 30, 2014. 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 $116.2 million decrease in fair value of our senior unsecured notes atSeptember 30, 2014.

Item 4. *Controls and Procedures*

(a) Evaluation of Disclosure Controls and Procedures

We carried out an evaluation, under the supervision and with the participation of our management, including the Chief Executive Officer and Chief Financial Officer of EnLink Midstream GP, LLC, of the effectiveness of our disclosure controls and procedures as of the end of the period covered by this report pursuant to Exchange Act Rules 13a-15 and 15d-15. Based on that evaluation, the Chief Executive Officer and Chief Financial Officer have concluded that, as of the end of the period covered by this report (September 30, 2014), our disclosure controls and procedures were effective to provide reasonable assurance that information required to be disclosed by us in the reports we file or submit under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time period specified in the applicable rules and forms, and that such information is accumulated and communicated to management, including the Chief Executive Officer and Chief Financial Officer, to allow timely decisions regarding required disclosure.

(b) Changes in Internal Control Over Financial Reporting

There has been no change in our internal control over financial reporting that occurred in the three months ended September 30, 2014 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

PART II—OTHER INFORMATION

Item 1. ***Legal Proceedings***

We are involved in various litigation and administrative proceedings arising in the normal course of business. In the opinion of management, any liabilities that may result from these claims would not individually or in the aggregate have a material adverse effect on our financial position or results of operations.

For a discussion of certain litigation and similar proceedings, please refer to Note 13, "Commitments and Contingencies," of the Notes to Condensed Consolidated Financial Statements, which is incorporated by reference herein.

Item 1A. ***Risk Factors***

Information about risk factors does not differ materially from that set forth in Part I, Item 1A of our Annual Report on Form 10-K for the fiscal year ended December 31, 2013 other than as supplemented by our Form 10-Q for the quarterly periods ended March 31, 2014 and June 30, 2014 in response to Part II, Item 1A. of such Form 10-Q. Such risk factors are incorporated herein by reference.

Item 6. ***Exhibits***

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

Number		Description
2.1**	—	Contribution Agreement, dated as of October 21, 2013, by and among Devon Energy Corporation, Devon Gas Corporation, Devon Gas Services, L.P., Southwestern Gas Pipeline, Inc., EnLink Midstream Partners, LP and EnLink Midstream Operating, LP (incorporated by reference to Exhibit 2.1 to our Current Report on Form 8-K dated October 21, 2013, filed with the Commission on October 22, 2013).
2.2**	—	Contribution and Transfer Agreement, dated as of October 22, 2014, by and between EnLink Midstream Partners, LP and EnLink Midstream, Inc. (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K dated October 22, 2014, filed with the Commission on October 22, 2014).
3.1	—	Certificate of Limited Partnership of Crosstex Energy, L.P. (incorporated by reference to Exhibit 3.1 to our Registration Statement on Form S-1, file No. 333-97779).
3.2	—	Certificate of Amendment to the Certificate of Limited Partnership of Crosstex Energy, L.P. (incorporated by reference to Exhibit 3.2 to our Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2012).
3.3	—	Second Amendment to the Certificate of Limited Partnership of Crosstex Energy, L.P. (incorporated by reference to Exhibit 3.3 to our Current Report on Form 8-K dated March 6, 2014, filed with the Commission on March 11, 2014).
3.4	—	Seventh Amended and Restated Agreement of Limited Partnership of EnLink Midstream Partners, LP dated July 7, 2014 (incorporated by reference to Exhibit 3.1 to our Current Report on Form 8-K dated July 7, 2014, filed with the Commission on July 7, 2014).
3.5	—	Certificate of Formation of Crosstex Energy GP, LLC (incorporated by reference to Exhibit 3.7 to our Registration Statement on Form S-1, file No. 333-97779).
3.6	—	Certificate of Amendment to the Certificate of Formation of Crosstex Energy GP, LLC (incorporated by reference to Exhibit 3.1 to our Current Report on Form 8-K dated March 6, 2014, filed with the Commission on March 11, 2014).
3.7	—	Third Amended and Restated Limited Liability Company Agreement of EnLink Midstream GP, LLC, dated as of July 7, 2014 (incorporated by reference to Exhibit 3.2 to our Current Report on Form 8-K dated July 7, 2014, filed with the Commission on July 7, 2014).
10.1†	—	Second Amendment to Employment Agreement, dated August 26, 2014, by and between EnLink Midstream GP, LLC and Michael J. Garberding (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K dated August 26, 2014, filed with the Commission on August 26, 2014).
10.2†	—	Form of Severance Agreement (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K dated September 17, 2014, filed with the Commission on September 23, 2014).
10.3†	—	Form of Change in Control Agreement (incorporated by reference to Exhibit 10.2 to our Current Report on Form 8-K dated September 17, 2014, filed with the Commission on September 23, 2014).
31.1*	—	Certification of the Principal Executive Officer.
31.2*	—	Certification of the Principal Financial Officer.
32.1*	—	Certification of the Principal Executive Officer and Principal Financial Officer pursuant to 18 U.S.C. Section 1350.
101*	—	The following financial information from EnLink Midstream Partners, LP's Quarterly Report on Form 10-Q for the quarter ended September 30, 2014, formatted in XBRL (eXtensible Business Reporting Language): (i) Condensed Consolidated Balance Sheets as of September 30, 2014 and December 31, 2013, (ii) Condensed Consolidated Statements of Operations for the three and nine months ended September 30, 2014 and 2013, (iii) Consolidated Statements of Changes in Partners' Equity for the nine months ended September 30, 2014, (iv) Consolidated Statements of Cash Flows for the nine months ended September 30, 2014 and 2013, and (v) the Notes to Condensed 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.

† This Exhibit is identified as a management contract or compensatory benefit plan or arrangement.

SIGNATURES

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

EnLink Midstream Partners, LP

By: EnLink Midstream GP, LLC,
its General Partner

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

November 5, 2014

Exhibit 31.1

CERTIFICATIONS

I, Barry E. Davis, President and Chief Executive Officer of EnLink Midstream GP, LLC, the general partner of the registrant, certify that:

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

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

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

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

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

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

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

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

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

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

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

/s/ BARRY E. DAVIS

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

Date: November 5, 2014

Exhibit 31.2

CERTIFICATIONS

I, Michael J. Garberding, Executive Vice President and Chief Financial Officer of EnLink Midstream GP, LLC, the general partner of the registrant, certify that:

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

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

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

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

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

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

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

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

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

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

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

/s/ MICHAEL J. GARBERDING

MICHAEL J. GARBERDING
Executive Vice President and Chief Financial Officer
(principal financial and accounting officer)

Date: November 5, 2014

Exhibit 32.1

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

In connection with the Quarterly Report of EnLink Midstream Partners, LP (the "Registrant") on Form 10-Q for the quarter ended September 30, 2014 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), each of the undersigned, Barry E. Davis, Chief Executive Officer of EnLink Midstream GP, LLC, and Michael J. Garberding, Chief Financial Officer of EnLink Midstream GP, LLC, certifies, pursuant to 18 U.S.C. section 1350, as adopted pursuant to section 906 of the Sarbanes-Oxley Act of 2002, that to his knowledge:

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

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

/s/ BARRY E. DAVIS
Barry E. Davis
Chief Executive Officer

November 5, 2014

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

November 5, 2014

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