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 March 31, 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 April 25, 2014, the Registrant had 109,051,011 common units and 120,542,441 Class B common units outstanding.

TABLE OF CONTENTS

ENLINK MIDSTREAM PARTNERS, LP

Condensed Consolidated Balance Sheets

	March 31, 2014 (Unaudited)	December 31, 2013
	(In millions)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 218.4	$ —
Accounts receivable:		
Trade, net of allowance for bad debt	51.6	0.4
Accrued revenue and other	254.8	—
Related Party	70.6	—
Fair value of derivative assets	0.5	—
Natural gas and natural gas liquids inventory, prepaid expenses and other	38.4	5.8
Assets held for disposition	—	72.7
Total current assets	634.3	78.9
Property and equipment, net of accumulated depreciation of $1,220.2 and $1,169.8, respectively	4,079.4	1,768.1
Fair value of derivative assets	0.5	—
Intangible assets, net of accumulated amortization of $1.7	389.1	—
Goodwill	2,438.1	401.7
Investments in unconsolidated affiliate	271.4	61.1
Other assets, net	4.5	—
Total assets	$ 7,817.3	$ 2,309.8
LIABILITIES AND PARTNERS' EQUITY		
Current liabilities:		
Accounts payable, drafts payable and other	$ 51.4	$ 1.7
Accrued gas and crude oil purchases	231.7	—
Fair value of derivative liabilities	0.9	—
Accrued capital expenditures	31.5	—
Contract liability	23.0	—
Other current liabilities	77.3	38.7
Accrued interest	9.6	—
Current portion of long-term debt	198.2	—
Liabilities held for disposition	—	37.0
Total current liabilities	623.6	77.4
Long-term debt	1,415.8	—
Asset retirement obligation	8.4	7.7
Other long-term liabilities	98.8	—
Deferred tax liability	72.1	440.9
Fair value of derivative liabilities	0.9	—
Partners' equity	5,597.7	1,783.8
Total liabilities and partners' equity	$ 7,817.3	$ 2,309.8

See accompanying notes to condensed consolidated financial statements.

ENLINK MIDSTREAM PARTNERS, LP

Condensed Consolidated Statements of Operations

	Three Months Ended March 31, 2014	Three Months Ended March 31, 2013
	(Unaudited) (In millions, except per unit amounts)	
Revenues:		
Revenues	$ 231.9	$ 41.8
Revenues - affiliates	491.9	485.1
Loss on derivative activity	(1.3)	—
Total revenues	722.5	526.9
Operating costs and expenses:		
Purchased gas, NGLs, condensate and crude oil (1)	538.9	395.4
Operating expenses (2)	46.0	41.0
General and administrative (3)	15.2	10.2
Depreciation and amortization	47.9	44.4
Total operating costs and expenses	648.0	491.0
Operating income	74.5	35.9
Other income (expense):		
Interest expense, net of interest income	(4.8)	—
Income from equity investment	4.2	1.0
Other expense	(0.7)	—
Total other (income) expense	(1.3)	1.0
Income from continuing operations before non-controlling interest and income taxes	73.2	36.9
Income tax provision	(19.6)	(13.4)
Net income from continuing operations	53.6	23.5
Discontinued operations:		
Income from discontinued operations, net of tax	1.0	6.5
Income from discontinued operations attributable to non-controlling interest, net of tax	—	0.6
Discontinued operations, net of tax	1.0	5.9
Net income	54.6	29.4
Net income attributable to the non-controlling interest	10.5	—
Net income attributable to EnLink Midstream Partners, LP	$ 44.1	$ 29.4
Predecessor interest in net income (4)	$ 35.5	$ 29.4
General partner interest in net income	$ 0.9	$ —
Limited partners' interest in net income attributable to EnLink Midstream Partners, LP	$ 7.7	$ —
Net income attributable to EnLink Midstream Partners, LP per limited partners' unit:		
Basic per common unit	$ 0.03	$ —
Diluted per common unit	$ 0.03	$ —

(1) Includes $325.8 million and $362.2 million affiliate purchased gas, NGLs, condensate and crude oil for the three months ended March 31, 2014 and March 31, 2013, respectively.
(2) Includes $5.9 million and $8.9 million affiliate operating expenses for the three months ended March 31, 2014 and March 31, 2013, respectively.
(3) Includes $8.3 million and $10.1 million affiliate general and administrative expenses for the three months ended March 31, 2014 and March 31, 2013, respectively.
(4) Represents net income attributable to the Predecessor for the periods prior to March 7, 2014.

See accompanying notes to condensed consolidated financial statements.

Table of Contents

ENLINK MIDSTREAM PARTNERS, LP

Consolidated Statement of Changes in Partners' Equity
Three Months Ended March 31, 2014

(Unaudited)
(In millions)

	Common Units		General Partner Interest		Predecessor Equity	Non-Controlling Interest	
	$	Units	$	Units	$	$	Total
Balance, December 31, 2013	$ —	—	$ —	—	$ 1,783.8	$ —	$ 1,783.8
Contributions by (distributions to) the Predecessor	—	—	—	—	(92.6)	—	(92.6)
Elimination of deferred taxes due to reorganization of predecessor	—	—	—	—	472.6	—	472.6
Issuance of units for reorganization of predecessor equity	1,099.6	120.5	—	—	(2,199.3)	1,099.7	—
Issuance of common units for acquisition of Partnership	3,329.4	109.1	48.7	1.6	—	—	3,378.1
Stock-based compensation	0.6	—	0.6	—	—	—	1.2
Net income	7.7	—	0.9	—	35.5	10.5	54.6
Balance, March 31, 2014	$ 4,437.3	229.6	$ 50.2	1.6	$ —	$ 1,110.2	$ 5,597.7

See accompanying notes to condensed consolidated financial statements.

ENLINK MIDSTREAM PARTNERS, LP

Consolidated Statements of Cash Flows

	Three Months Ended March 31, 2014	Three Months Ended March 31, 2013
	(Unaudited) (In millions)	
Cash flows from operating activities:		
Net income from continuing operations	$ 53.6	$ 23.5
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	47.9	44.4
Accretion expense	0.2	0.1
Deferred tax benefit	19.5	(2.2)
Non-cash stock-based compensation	1.2	—
Loss on derivatives recognized in net income	1.3	—
Cash paid on derivatives	(0.6)	—
Amortization of debt issue costs	0.1	—
Amortization of premium on notes	(0.4)	—
Distribution of earnings from equity investment	0.1	—
Income from equity investment	(4.2)	(1.0)
Changes in assets and liabilities:		
Accounts receivable, accrued revenue and other	46.0	—
Natural gas and natural gas liquids, prepaid expenses and other	(7.3)	1.4
Accounts payable, accrued gas and crude oil purchases and other accrued liabilities	(41.3)	2.7
Net cash provided by operating activities	116.1	68.9
Cash flows from investing activities:		
Additions to property and equipment	(86.1)	(99.9)
Acquisition of business	(33.9)	—
Distribution from equity investment company in excess of earnings	2.6	—
Net cash used in investing activities	(117.4)	(99.9)
Cash flows from financing activities:		
Proceeds from borrowings	1,247.0	—
Payments on borrowings	(996.9)	—
Payments on capital lease obligations	(0.8)	—
Decrease in drafts payable	(2.6)	—
Debt refinancing costs	(4.9)	—
Contributions by (distributions to) the partners	(22.1)	25.2
Net cash provided by financing activities	219.7	25.2
Cash flow from discontinued operations:		
Net cash provided by operating activities	5.0	4.7
Net cash used in investing activities	(0.6)	(1.9)
Net cash used in financing activities – net distributions to Devon and non-controlling interests	(4.4)	(12.6)
Net cash used in discontinued operations	—	(9.8)
Net increase (decrease) in cash and cash equivalents	218.4	(15.6)
Cash and cash equivalents, beginning of period	—	15.6
Cash and cash equivalents, end of period	$ 218.4	$ —
Cash paid for interest	$ 4.6	$ —

See accompanying notes to condensed consolidated financial statements.

ENLINK MIDSTREAM PARTNERS, LP

Notes to Condensed Consolidated Financial Statements

March 31, 2014
(Unaudited)

(1) General

In this report, the terms "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 in2002. 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 owns ENLC's managing member and Class B 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 representing a new class 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 Holding 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 $2.2 million at March 31, 2014 which approximate the fair value of these imbalances. The Partnership had imbalance receivables of$2.3 million at March 31, 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.

(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 to be 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 months ended March 31, 2014, by approximately $2.0 million, or less than $0.01 per unit.

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, 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 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 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 or 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 $2.4 billion of goodwill at March 31, 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 fifteen to twenty years.

The following table represents the Partnership's total intangible assets as of March 31, 2014 (in millions):

	Gross Carrying Amount	Accumulated Amortization	Net Carrying Amount
Customer relationships	$ 390.8	$ (1.7)	$ 389.1

The weighted average amortization period for intangible assets is 15.7 years. Amortization expense for intangibles was approximately $1.7 million for the three months ended March 31, 2014.

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

2014	$	18.9
2015		25.2
2016		25.2
2017		25.2
2018		25.2
Thereafter		269.4
Total	$	389.1

(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 a $94.2 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. 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 by the portion of the monthly product purchase costs in excess of market associated with this onerous performance obligation recorded as of March 7, 2014 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 derivative gain (loss) in the period of change.

Realized gains and losses on commodity related derivatives are recorded as gain or loss on derivatives 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 March 31, 2014.

During the three months ended March 31, 2014, the Partnership had no third party customer that individually represented greater than10.0% of its midstream revenues other than affiliate transactions with Devon that represented 68.1% of the consolidated midstream revenues. 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 months ended March 31, 2014, such expenditures were not material.

(p) Share-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 stock-based awards in its consolidated financial statements in accordance with FASB ASC 718. The Partnership and ENLC each have similar unit or share-based payment plans for employees. Share-based compensation associated with ENLC's share-based compensation plans awarded to 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

We have reviewed all recently issued accounting pronouncements that became effective during thethree months ended March 31, 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 $33.9 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	$	436.1
Property, plant and equipment		2,294.6
Intangibles assets		390.8
Equity investment		221.5
Goodwill		2,036.3
Other long-term assets		1.1
Liabilities assumed:		
Current liabilities		(473.1)
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 material change. All of the goodwill is non-deductible for tax purposes.

For the period from March 7, 2014 to March 31, 2014, the Partnership recognized $198.9 million of revenues and $196.0 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 three months ended March 31, 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 is reflected below.

	Three Months Ended			
	March 31, 2014		March 31, 2013	
	(in millions, except for per unit data)			
Pro forma total revenues	$	892.5	$	593.6
Pro forma net income	$	50.3	$	59.2
Pro forma net income attributable to EnLink Midstream Partners, LP	$	19.3	$	32.8
Pro forma net income per common unit:				
Basic	$	0.06	$	0.15
Diluted	$	0.06	$	0.15

(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 Gulf Coast Fractionators, 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.

Historical Customer Relationship with Devon

As noted above, we maintained a customer relationship with Devon prior to the business combination pursuant to which certain of our 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 July 2014 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 our subsidiaries has agreements with a subsidiary of Devon pursuant to which our subsidiary purchases and sells NGLs and pays or receives, as applicable, a margin-based fee. These NGL purchase and sale agreements have either month-to-month terms or expire in July 2014, depending on the agreement, but none renews automatically.

Transition Services Agreement

In connection with the consummation of the business combination, we entered into a transition services agreement with Devon pursuant to which Devon provides certain services to us with respect to the business and operations of Midstream Holdings, including IT, accounting, pipeline integrity, compliance management and procurement services, and we provide certain services to Devon and its subsidiaries, including IT, human resources and other commercial and operational services.

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 Gulf Coast Fractionators, or 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 Services for the expenses it incurs in providing the storage services. The Partnership expects this agreement will have minimal to no impact on its 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 made to or received from Devon, all of which are settled through an adjustment to equity prior to March 7, 2014 (in millions):

	Three Months Ended March 31, 2014	Three Months Ended March 31, 2013
Continuing Operations:		
Operating revenues - affiliates	$ (436.4)	$ (485.1)
Operating expenses - affiliates	340.0	381.2
Net affiliate transactions	(96.4)	(103.9)
Capital expenditures	21.3	99.9
Other third-party transactions, net	53.0	45.2
Total third-party transactions	74.3	145.1
Net cash distributions from (to) Devon - continuing operations	(22.1)	41.2
Non-cash distribution of net assets to Devon	(26.2)	—
Total net contributions (distributions) per equity	$ (48.3)	$ 41.2
Discontinued operations:		
Operating revenues - affiliates	$ (10.4)	$ (23.1)
Operating expenses - affiliates	5.0	8.3
Cash used in financing activities - affiliates	—	(2.0)
Net affiliate transactions	(5.4)	(16.8)
Capital expenditures	0.6	2.7
Other third-party transactions, net	0.4	1.5
Net third-party transactions	1.0	4.2
Net distributions to Devon and non-controlling interests - discontinued operations	(4.4)	(12.6)
Non-cash distribution of net assets to Devon	(39.9)	—
Total net distributions per equity	$ (44.3)	$ (12.6)
Total contributions (distributions) - continuing and discontinued operations	$ (92.6)	$ 28.6

For the three months ended March 31, 2014 and 2013, Devon was a significant customer to the Partnership. Devon accounted for 68.1% and 92.1% of the Partnership's revenues for the three months ended March 31, 2014 and 2013, respectively. The affiliate revenues after March 7, 2014 were $55.5 million. Additionally, the Partnership had an accounts receivable balance related to transactions with Devon of $57.8 million as of March 31, 2014. The remaining related party receivable balance of $12.8 million is attributable to transactions with ENLC.

Share-based compensation costs included in the management services fee charged to Midstream Holdings by Devon were approximately $2.8 million and $3.1 million for the three months ended March 31, 2014 and 2013. Pension, postretirement and employee savings plan costs included in the management services fee charged to the Partnership by Devon were approximately $1.6 million and $2.1 million, for the three months ended March 31, 2014 and 2013. These amounts are included in general and administrative expenses in the accompanying statements of operations.

(5) Long-Term Debt

As of March 31, 2014, long-term debt consisted of the following (in millions):

		March 31, 2014
Bank credit facility (due 2019), interest based on Prime and/or LIBOR plus an applicable margin, interest rate at March 31, 2014 was 3.5%	$	—
Senior unsecured notes (due 2018), including a premium of $9.3 million, which bear interest at the rate of 8.875% (1)		198.2
Senior unsecured notes (due 2019), net of discount of $3.0 million, which bear interest at the rate of 2.70%		397.0
Senior unsecured notes (due 2022), including a premium of $29.2 million, which bear interest at the rate of 7.125%		225.8
Senior unsecured notes (due 2024), net of discount of $3.7 million, which bear interest at the rate of 4.40%		446.3
Senior unsecured notes (due 2044), net of discount of $3.3 million, which bear interest at the rate of 5.60%		346.7
	$	1,614.0
Less: Current portion	$	(198.2)
Debt classified as long-term	$	1,415.8

(1) On April 18, 2014, we redeemed the remaining $198.2 million outstanding balance of the 2018 Notes.

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 March 31, 2014, there were $56.8 million in outstanding letters of credit and no outstanding borrowings under the Partnership’s bank credit facility, leaving approximately $943.2 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.

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.

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. The remaining 2018 Notes were recorded in current maturities of long-term debt as of March 31, 2014 at $198.2 million and were redeemed on April 18, 2014 for $200.2 million, including accrued interest.

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 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;
- failures 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 $472.6 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 $61.9 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) 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 declared a first quarter 2014 distribution on its common units and Class B Units of $0.36 per unit and $0.10 per unit, respectively, to be paid on

May 14, 2014. Distributions declared for the Class B Units represents 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.

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.

(b) 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 period from March 7, 2014 through March 31, 2014 (in millions except per unit amounts):

Limited partners' interest in net income	$	7.7
Distributed earnings allocated to:		
Common units and Class B Units (1) (2)	$	51.3
Unvested restricted units (1)		0.2
Total distributed earnings	$	51.5
Undistributed loss allocated to:		
Common units and Class B Units (2)	$	(43.7)
Unvested restricted units		(0.1)
Total undistributed loss	$	(43.8)
Net income allocated to:		
Common units and Class B Units (2)	$	7.6
Unvested restricted units		0.1
Total limited partners' interest in net income	$	7.7
Basic and diluted net income per unit:		
Basic	$	0.03
Diluted	$	0.03

(1) Three months ended March 31, 2014 represents a declared distribution of $0.36 per unit for common units payable on May 14, 2014.
(2) Includes declared distribution of $0.10 per unit for Class B Units payable on May 14, 2014.

The following are the unit amounts used to compute the basic and diluted earnings per limited partner unit for the period from March 7, 2014 through March 31, 2014 (in millions):

	Three Months Ended March 31, 2014
Basic weighted average units outstanding:	
Weighted average limited partner basic common units outstanding	109.0
Weighted average Class B Units outstanding	120.5
Total weighted average limited partner common units outstanding	229.6
Diluted weighted average units outstanding:	
Weighted average limited partner basic common units outstanding	229.6
Dilutive effect of restricted units issued	0.6
Total weighted average limited partner diluted common units outstanding	230.2

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 6(a). The General Partner's share of net income consists of incentive distributions to the extent earned, a deduction for stock-based compensation attributable to ENLC's restricted units and the percentage interest of the Partnership's net income adjusted for ENLC's stock-based compensation specifically allocated to the General Partner. The net income allocated to the General Partner is as follows for the period from March 7, 2014 through March 31, 2014 (in millions):

Income allocation for incentive distributions	$	1.4
Stock-based compensation attributable to ENLC's restricted units		(0.6)
General Partner interest in net income		0.1
General Partner share of net income	$	0.9

(8) Asset Retirement Obligations

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

	March 31, 2014		March 31, 2013	
	(in millions)			
Beginning asset retirement obligations	$	7.7	$	9.1
Revisions to existing liabilities		—		0.4
Liabilities acquired		0.5		—
Accretion		0.2		0.1
Ending asset retirement obligations	$	8.4	$	9.6

(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 March 31, 2014 and December 31, 2013 and a 30.6% ownership interest in Howard Energy Partners ("HEP") at March 31, 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
March 31, 2014:			
Distributions	$ —	$ 2.7	$ 2.7
Equity in income	$ 4.1	$ 0.1	$ 4.2
March 31, 2013:			
Equity in income	$ 1.0	$ —	$ 1.0

(1) Includes income and distributions for the period from March 7, 2014 through March 31, 2014.

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

	March 31, 2014	December 31, 2013
Gulf Coast Fractionators (1)	$ 52.1	$ 61.1
Howard Energy Partners	219.3	—
Total investments in unconsolidated affiliates	$ 271.4	$ 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 March 31, 2014	Three Months Ended March 31, 2013
Cost of share-based compensation allocated Predecessor general and administrative expense (1)	$ 2.8	$ 3.1
Cost of share-based compensation charged to general and administrative expense	1.0	—
Cost of share-based compensation charged to operating expense	0.2	—
Total amount charged to income	$ 4.0	$ 3.1

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

The Partnership accounts for share-based compensation in accordance with FASB ASC 718, which requires that compensation related to all stock-based awards, including stock 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 three months ended March 31, 2014 is provided below:

	Three Months Ended March 31, 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	361,926	31.55
Forfeited	(3,971)	31.48
Non-vested, end of period	729,180	$ 31.02
Aggregate intrinsic value, end of period (in millions)	$ 22.2	

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 the restricted incentive units outstanding and the current share-based compensation cost calculations at March 31, 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.

As of March 31, 2014, there was $16.2 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 2.4 years.

(c) Unit Options

During the three months ended March 31, 2014, 3,776 unit options of the Partnership were exercised with an intrinsic value of $0.1 million. As of March 31, 2014, all unit options were fully vested and fully expensed.

(d) EnLink Midstream, LLC's Restricted 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 11,000,000 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 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 units activities for the three months ended March 31, 2014 is provided below:

EnLink Midstream, LLC Restricted Units:	Three Months Ended March 31, 2014 Number of Units	Three Months Ended March 31, 2014 Weighted Average Grant-Date Fair Value
Non-vested, beginning of period	—	$ —
Assumed in business combination	435,674	37.60
Granted	339,665	36.58
Forfeited	(3,415)	36.60
Non-vested, end of period	771,924	$ 37.16
Aggregate intrinsic value, end of period (in millions)	$ 26.2	

Restricted 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 units outstanding and the current share-based compensation cost calculations at March 31, 2014. ENLC issued restricted units in 2014 to officers and other employees. These restricted units typically vest at the end of three years and are included in restricted units outstanding.

As of March 31, 2014, there was $19.3 million of unrecognized compensation costs related to non-vested ENLC restricted units. The cost is expected to be recognized over a weighted average period of 2.4 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.

The Partnership commonly enters into various types of derivative financial transactions including "swing swaps," "third party on-system financial swaps," "storage swaps," "basis swaps," "processing margin swaps," "liquids swaps" and "put options." Swing swaps are generally short-term in nature (one month), and are usually entered into to protect against changes in the volume of daily versus first-of-month index priced gas supplies or markets. Third party on-system financial swaps are hedges that the Partnership enters into on behalf of its customers who are connected to its systems, wherein the Partnership fixes a supply or market price for a period of time for its customers and simultaneously enters into the derivative transaction. Storage swap transactions protect against changes in the value of gas that the Partnership has stored to serve various operational requirements. Basis swaps are used to hedge basis location price risk due to buying gas into one of our systems on one index and selling gas off that same system on a different index. Processing margin financial swaps are used to hedge fractionation spread risk at our processing plants relating to the option to process versus bypassing our equity gas. Liquids financial swaps are used to hedge price risk on liquid swaps not otherwise designated as cash flow hedges. Put options are purchased to hedge against declines in pricing and as such represent options, not obligations, to sell the related underlying volumes at a fixed price.

The components of loss on derivative activity in the consolidated statements of operations relating to commodity swaps are as follows for the period from March 7, 2014 through March 31, 2014 (in millions):

Change in fair value of derivatives	$ (0.7)
Realized losses on derivatives	(0.6)
Loss on derivative activity	$ (1.3)

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

	March 31, 2014
Fair value of derivative assets — current	$ 0.5
Fair value of derivative assets — long term	0.5
Fair value of derivative liabilities — current	(0.9)
Fair value of derivative liabilities — long term	(0.9)
Net fair value of derivatives	$ (0.8)

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 March 31, 2014. The remaining term of the contracts extend no later than December 2016.

			March 31, 2014	
Commodity	Instruments	Unit	Volume	Fair Value
			(In millions)	
NGL (short contracts)	Swaps	Gallons	(69.0)	$ (0.5)
NGL (long contracts)	Swaps	Gallons	54.8	(0.5)
Natural Gas (long contracts)	Swaps	Mmbtu	0.3	0.1
Condensate (short contracts)	Swaps	Bbl	(0.1)	0.1
Total fair value of derivatives				$ (0.8)

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 March 31, 2014 of $0.7 million would be reduced to $0.3 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
March 31, 2014	$ (0.4)	$ (0.1)	$ (0.3)	$ (0.8)

(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):

	March 31, 2014 Level 2
Commodity Swaps*	$ (0.8)
Total	$ (0.8)

* 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):

	March 31, 2014	
	Carrying Value	Fair Value
Long-term debt	$ 1,614.0	$ 1,664.1
Obligations under capital leases	$ 22.5	$ 22.4

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 no borrowings under its revolving credit facility as of March 31, 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 March 31, 2014, the Partnership had borrowings totaling $397.0 million, $446.3 million and $346.7 million, net of discount, under the 2019 Notes, 2024 Notes and 2044 Notes, with a fixed rate of2.70%, 4.40% and 5.60%, respectively. Additionally, the Partnership had borrowings of $198.2 million and $225.8 million under the 2018 Notes and 2022 Notes with a fixed rate of8.875% and 7.125%, respectively, as of March 31, 2014. The fair value of all senior unsecured notes as of March 31, 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 gathering, processing or transmitting natural gas, NGLs 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 January 2012, a plaintiff in one of these lawsuits was awarded a judgment of $2.0 million. The Partnership has appealed the matter and has posted a bond to secure the judgment pending its resolution. The Partnership has accrued a $2.0 million liability related to this matter. 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.

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 federal court. 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.

(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 March 31, 2014						
Sales to external customers	$ 48.3	$ 153.2	$ 11.5	$ 18.9	$ —	$ 231.9
Sales to affiliates	335.9	0.5	162.9	—	(7.4)	491.9
Purchased gas, NGLs, condensate and crude oil	(257.7)	(140.5)	(133.8)	(14.3)	7.4	(538.9)
Operating expenses	(31.7)	(5.1)	(6.7)	(2.5)	—	(46.0)
Loss on derivative activity	—	—	—	—	(1.3)	(1.3)
Segment profit	$ 94.8	$ 8.1	$ 33.9	$ 2.1	$ (1.3)	$ 137.6
Depreciation and amortization	$ (27.2)	$ (5.2)	$ (14.2)	$ (1.2)	$ (0.1)	$ (47.9)
Goodwill	$ 1,256.7	$ 885.1	$ 190.3	$ 106.0	$ —	$ 2,438.1
Capital expenditures	$ 25.1	$ 22.1	$ 10.2	$ 0.4	$ 5.5	$ 63.3
Three Months Ended March 31, 2013						
Sales to external customers	$ 30.5	$ —	$ 11.3	$ —	$ —	$ 41.8
Sales to affiliates	325.6	—	159.5	—	—	485.1
Purchased gas, NGLs, condensate, and crude oil	(257.4)	—	(138.0)	—	—	(395.4)
Operating expenses	(33.8)	—	(7.2)	—	—	(41.0)
Segment profit	$ 64.9	$ —	$ 25.6	$ —	$ —	$ 90.5
Depreciation and amortization	$ (26.7)	$ —	$ (17.7)	$ —	$ —	$ (44.4)
Goodwill	$ 325.4	$ —	$ 76.3	$ —	$ —	$ 401.7
Capital expenditures	$ 50.8	$ —	$ 32.4	$ —	$ —	$ 83.2

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

	March 31, 2014	December 31, 2013
Segment Identifiable Assets:	(In millions)	
Texas	$ 3,171.0	$ 1,460.0
Louisiana	2,714.4	—
Oklahoma	896.4	777.1
Ohio River Valley	505.7	—
Corporate	529.8	72.7
Total identifiable assets	$ 7,817.3	$ 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 March 31,	
	2014	2013
Segment profits	$ 137.6	$ 90.5
General and administrative expenses	(15.2)	(10.2)
Depreciation and amortization	(47.9)	(44.4)
Operating income	$ 74.5	$ 35.9

(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 Gulf Coast Fractionators, 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:

ENLINK MIDSTREAM PARTNERS, LP

Notes to Condensed Consolidated Financial Statements-(Continued)

	Three Months Ended March 31, 2014	Three Months Ended March 31, 2013
	(in millions)	
Operating revenues:		
Operating revenues	$ 6.8	$ 11.4
Operating revenues - affiliates	10.5	23.1
Total operating revenues	17.3	34.5
Operating expenses:		
Operating expenses	15.7	24.4
Total operating expenses	15.7	24.4
Income before income taxes	1.6	10.1
Income tax expense	0.6	3.6
Net income	1.0	6.5
Net income attributable to non-controlling interest	—	(0.6)
Net income including non-controlling interest	$ 1.0	$ 5.9

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 March 31, 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

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. 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 Gulf Coast Fractionators, 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 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 7,300 miles of pipelines, twelve natural gas processing plants, six 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 Gulf Coast Fractionators 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 principles, 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 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 March 31, 2014 reflects a liability of $94.2 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 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, EnLink Midstream Operating, LP (formerly known as Crosstex Energy Services, L.P.), a wholly-owned subsidiary of 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 Gulf Coast Fractionators 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 5, 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

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. The available supply for the Cajun-Sibon Phase I pipeline expansion has been near its full capacity of 70,000 Bbls/d of rawmake NGLs during the first quarter of 2014. The throughput through the pipeline averaged approximately 54,000 Bbls/d during the first quarter of 2014 as we worked through some minor operational issues and the pipeline expansion is now operating near full capacity. Additionally, Eunice fractionator in South Louisiana experienced some minor operational issues and averaged approximately 38,000 Bbls/d during the first quarter of 2014. These issues have been substantially resolved and the fractionator is currently running near capacity, with plant volumes currently ranging between 50,000 and 55,000 Bbls/d.

Cajun-Sibon Phase II will further enhance our Louisiana NGL business with significant additions to the Cajun-Sibon Phase I NGL pipeline extension and Eunice expansion. Construction of Cajun-Sibon Phase II continues to progress and will further increase the Cajun-Sibon pipeline capacity by an additional 50,000 Bbls/d to a total of 120,000 Bbls/d. Construction on our new 100,000 Bbl/d fractionator at our Plaquemine gas processing complex is on schedule and near completion. Phase II is expected to be complete during the fourth quarter of 2014.

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 the fourth quarter of 2013, we commenced construction of a new natural gas processing complex and rich gas gathering pipeline system in the Permian Basin called Bearkat. The initial construction included treating, processing and gas takeaway solutions for regional producers. The project, which will be fully owned by us, is supported by a 10-year, fee-based contract.

Bearkat will be strategically located near our existing Deadwood joint venture assets in Glasscock County, Texas. The processing plant will have an initial capacity of 60 MMcf/d, increasing the Partnership’s total operated processing capacity in the Permian to approximately 115 MMcf/d. We will also construct 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 a capacity of approximately 100 MMcf/d and will provide gas takeaway solutions for constrained producer customers in Howard, Martin and Glasscock counties. The entire project is expected to be completed in the second half of 2014.

Senior Unsecured Notes. 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 (as defined below), 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.

On March 12, 2014, we commenced a tender offer to purchase any and all of our outstanding 8.875% Senior Notes due (the "2018 Notes"). Approximately $536.1 million, or approximately 74%, of the 2018 Notes were validly tendered and not withdrawn prior to the expiration of the tender offer, and on March 19, 2014, we made 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.

Credit Facility. On February 20, 2014, we entered into a $1.0 billion unsecured revolving credit facility, which includes a $500.0 million letter of credit subfacility (the “credit facility”). 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. The 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 credit facility, which definition includes projected EBITDA from certain capital expansion projects) of no more than 5.0 to 1.0. If we consummate one or more acquisitions in which the aggregate purchase price is $50.0 million or more, 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 credit facility bear interest at our 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 our credit rating. Upon breach by us of certain covenants governing the credit facility, amounts outstanding under the credit facility, if any, may become due and payable immediately.

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 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 noncontrolling 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.

Adjusted EBITDA should not be considered an alternative to, or more meaningful than, net income, 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 table provides a reconciliation of net income to adjusted EBITDA:

	Three Months Ended March 31,	
	2014	**2013**
Net income	$ 54.6	$ 29.4
Interest expense	4.8	—
Depreciation and amortization	47.9	44.4
Income from equity investment	(4.2)	(1.0)
Distribution from equity investment	2.7	—
Stock-based compensation	4.0	3.1
Income Taxes	19.6	13.4
Other (a)	0.8	—
Adjusted EBITDA before non-controlling interest	130.2	89.3
Non-controlling interest share of adjusted EBITDA	(14.8)	—
Adjusted EBITDA net to EnLink Midstream Partners, LP	$ 115.4	$ 89.3

(a) Includes financial derivatives marked-to-market and other non-cash items.

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 March 31,	
	2014	2013
	(in millions)	
Total gross operating margin	$ 183.6	$ 131.5
Add (deduct):		
Operating expenses	(46.0)	(41.0)
General and administrative expenses	(15.2)	(10.2)
Depreciation and amortization	(47.9)	(44.4)
Operating income	$ 74.5	$ 35.9

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 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 quarter ended March 31, 2013 may not be comparable to our financial results for the quarter ended March 31, 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 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 quarter ended March 31, 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 Gulf Coast Fractionators, 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 March 31, 2014	2013
	(in millions, except volumes)	
Texas Segment		
Revenues	$ 384.2	$ 356.1
Purchased gas and NGLs	(257.7)	(257.4)
Total gross operating margin	$ 126.5	$ 98.7
Louisiana Segment		
Revenues	$ 153.7	$ —
Purchased gas, NGLs and crude oil	(140.5)	—
Total gross operating margin	$ 13.2	$ —
Oklahoma Segment		
Revenues	$ 174.4	$ 170.8
Purchased gas and NGLs	(133.8)	(138.0)
Total gross operating margin	$ 40.6	$ 32.8
ORV Segment		
Revenues	$ 18.9	$ —
Purchased crude oil and condensate	(14.3)	—
Total gross operating margin	$ 4.6	$ —
Corporate		
Revenues	$ (8.7)	$ —
Purchased gas and NGLs	7.4	—
Total gross operating margin	$ (1.3)	$ —
Total		
Revenues	$ 722.5	$ 526.9
Purchased gas, NGLs, condensate and crude oil	(538.9)	(395.4)
Total gross operating margin	$ 183.6	$ 131.5
Midstream Volumes:		
Texas		
Gathering and Transportation (MMBtu/d) (1)	2,952,200	2,131,000
Processing (MMBtu/d) (1)	1,128,300	788,000
Louisiana (2)		
Gathering and Transportation (MMBtu/d)	417,000	—
Processing (MMBtu/d)	642,700	—
NGL Fractionation (Gals/d)	3,291,900	—
Oklahoma (3)		
Gathering and Transportation (MMBtu/d)	411,800	393,000
Processing (MMBtu/d)	425,400	381,000
ORV (2)		
Crude Oil Handling (Bbls/d)	11,900	—
Brine Disposal (Bbls/d)	4,600	—

(1) Volumes include volumes per day based on 90 day periods for Midstream Holdings operations plus incremental volumes based on the 25 day period from March 7 to March 31, 2014 for the Partnership's legacy operations in Texas.

(2) Volumes include volumes per day based on the 25 day period from March 7 to March 31, 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 90 day periods for Midstream Holdings operations. The Partnership did not have any legacy operations in Oklahoma.

Three Months Ended March 31, 2014 Compared to Three Months Ended March 31, 2013

Gross Operating Margin. Gross operating margin increased $52.1 million, or 39.6% for the three months ended March 31, 2014 compared to $131.5 million for the three months ended March 31, 2013. Of this increase in gross operating margin, $26.9 million is attributable to the legacy Partnership assets associated with the business combination effective on March 7, 2014. Of this increase in gross operating margin, $25.2 million is related to Midstream Holdings, approximately $4.2 million of which is the result of the new fixed-fee arrangements with Devon entered into in connection with the business combination, with the remaining increase primarily driven by an increase in commodity prices under Predecessor percent of proceeds contracts.

Operating Expenses. Operating expenses were $46.0 million for the three months ended March 31, 2014 compared to $41.0 million for the three months ended March 31, 2013, an increase of $5.0 million, or 12.2%. Of this increase in operating expenses, $11.6 million is attributable to the legacy Partnership assets, partially offset by a decrease in Midstream Holdings' operating expenses of $6.6 million due to both lower ad valorem tax assessments and repair costs.

General and Administrative Expenses. General and administrative expenses were $15.2 million for the three months ended March 31, 2014 compared to $10.2 million for the three months ended March 31, 2013, an increase of $5.0 million, or 49.0%. The change in general administrative expenses is comprised of a $3.0 million increase related to legacy Company assets and an increase of approximately $2.0 million related to Midstream Holdings due to higher compensation expense.

Depreciation and Amortization. Depreciation and amortization expenses were $47.9 million for the three months ended March 31, 2014 compared to $44.4 million for the three months ended March 31, 2013, an increase of $3.5 million, or 7.9%. The primary drivers for the change is a decrease of $5.9 million in depreciation and amortization expense related to Midstream Holdings, approximately $2.0 million of which is due to the change in depreciation methodology from the units-of-production method to the straight-line method as well as 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. These decreases were offset by an increase in depreciation expense of $9.4 million related to the legacy Partnership assets acquired in March 2014.

Interest Expense. Interest expense was $4.8 million for the three months ended March 31, 2014. There was no interest expense for thethree months ended March 31, 2013 as Midstream Holdings did not have any debt. Net interest expense consists of the following (in millions):

	Three Months Ended March 31, 2014
Senior notes	$ 5.3
Bank credit facility	0.6
Capitalized interest	(1.1)
Amortization of debt issue cost, discount and premium	(0.2)
Other	0.2
Total	$ 4.8

Income from Equity Investments. Income from equity investments was $4.2 million for the three months ended March 31, 2014 as compared to $1.0 million for the three months ended March 31, 2013, an increase of $3.2 million. The increase primarily relates to our investment in Gulf Coast Fractionator ("GCF") due to turnaround downtime experienced during the historical comparative period.

Income Tax Expense. Income tax expense was $19.6 million for the three months ended March 31, 2014 as compared to $13.4 million for the three months ended March 31, 2013, an increase of $6.2 million. This increase primarily relates to an increase in taxable income related to the Predecessor, which was a taxable entity prior to the business combination on March 7, 2014. The remaining increase relates to an increase in Texas Margin tax related to Midstream Holdings, which became an non-taxable entity subsequent to the business combination and is not subject to federal and state income taxes, except the Texas Margin tax.

Net Income from Discontinued Operations. Net income from discontinued operations was$1.0 million for the three months ended March 31, 2014 as compared to $5.9 million for the three months ended March 31, 2013, a decrease of $4.9 million. The decrease is due to Midstream Holdings' discontinued operations for the period ended March 31, 2013 which included assets that were sold during 2013, while the period ended March 31, 2014 includes Predecessor assets that were not contributed to Midstream Holdings as part of the business combination.

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 evaluate goodwill for impairment annually 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 $116.1 million for the three months ended March 31, 2014 compared to $68.9 million for the three months ended March 31, 2013. Operating cash flows and changes in working capital for comparative periods were as follows (in millions):

	Three Months Ended March 31,	
	2014	2013
Operating cash flows before working capital	$ 118.7	$ 64.8
Changes in working capital	$ (2.6)	$ 4.1

The primary reason for the increase in operating cash flows before working capital of $53.9 million from 2013 to 2014 relates to an increase in gross operating margin from the acquired legacy Partnership assets and Midstream Holdings assets. Further, the increase in working capital for 2014 relates to the Predecessor's net settlement of receivables and payables with Devon in 2013 as compared to no net settlement in 2014.

Cash Flows from Investing Activities. Net cash used in investing activities was $117.4 million for the three months ended March 31, 2014 and $99.9 million for the three months ended March 31, 2013. Our primary investing cash flows were acquisition costs and capital expenditures, net of accrued amounts, as follows (in millions):

	Three Months Ended March 31,	
	2014	2013
Growth capital expenditures	$ 82.3	$ 73.9
Maintenance capital expenditures	3.8	26.0
Acquisition	33.9	—
Distribution from unconsolidated affiliates	(2.6)	—
Total	$ 117.4	$ 99.9

Cash Flows from Financing Activities. Net cash provided by financing activities was $219.7 million for the three months ended March 31, 2014 and $25.2 million for three months ended March 31, 2013. All predecessor financing activities from January 1, 2014 through March 6, 2014 and the three months ended March 31, 2013 totaling $22.1 million and $25.2 million, respectively, are reflected in contributions (distributions) to predecessor. Our primary financing activities subsequent to March 7, 2014 consist of the following (in millions):

	Three Months Ended March 31,
	2014
Net borrowings (repayments) on bank credit facility	$ (377.0)
Senior unsecured notes borrowings	1,190.0
Partial redemption of 2018 Notes	(562.9)
Net repayments under capital lease obligations	(0.8)
Debt refinancing costs	(4.9)

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 $22.1 million to Devon for the three months ended March 31, 2014 and contributions of $25.2 million for the three months ended March 31, 2013.

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 three months ended March 31, 2014 was as follows (in millions):

	Three Months Ended March 31, 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. We are currently in the initial phase of constructing the replacement pipeline in our rerouted location and anticipate services will resume during the second quarter of 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. We cannot give assurance that we will be able to fully recover our losses through insurance recovery or claims against responsible parties.

Capital Requirements. During the three months ended March 31, 2014, capital investments were $82.3 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 $435.0 million to $500.0 million related to identified growth projects. 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 March 31, 2014.

Total Contractual Cash Obligations. A summary of contractual cash obligations as of March 31, 2014 is as follows (in millions):

	Payments Due by Period						
	Total	2014	2015	2016	2017	2018	Thereafter
Long-term debt obligations*	$ 1,585.4	$ 188.9	$ —	$ —	$ —	$ —	$ 1,396.5
Interest payable on fixed long-term debt obligations	964.3	44.4	64.2	64.2	64.2	64.2	663.1
Capital lease obligations	26.1	3.4	4.6	4.6	6.7	2.9	3.9
Operating lease obligations	51.2	5.2	10.7	8.5	5.3	5.8	15.7
Purchase obligations	21.9	21.9	—	—	—	—	—
Consulting agreement	3.3	3.3	—	—	—	—	—
Delivery contract obligation	94.1	13.5	17.9	17.9	17.9	17.9	9.0
Inactive easement commitment**	9.0	1.0	1.0	1.0	1.0	1.0	4.0
Uncertain tax position obligations	3.9	3.9	—	—	—	—	—
Total contractual obligations	$ 2,665.1	$ 272.0	$ 80.5	$ 78.3	$ 77.2	$ 73.9	$ 2,083.2

* Effective as of April 18, 2014 we redeemed approximately $188.9 million in aggregate principal of the 2018 Notes pursuant to the terms of the indenture governing such notes.

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

Indebtedness

As of March 31, 2014, long-term debt consisted of the following (in millions):

	March 31, 2014
Bank credit facility (due 2019), interest based on Prime and/or LIBOR plus an applicable margin, interest rate at March 31, 2014 was 3.5%	$ —
Senior unsecured notes (due 2018), including a premium of $9.3 million, which bear interest at the rate of 8.875% (1)	198.2
Senior unsecured notes (due 2019), net of discount of $3.0 million, which bear interest at the rate of 2.70%	397.0
Senior unsecured notes (due 2022), including a premium of $29.2 million, which bear interest at the rate of 7.125%	225.8
Senior unsecured notes (due 2024), net of discount of $3.7 million, which bear interest at the rate of 4.40%	446.3
Senior unsecured notes (due 2044), net of discount of $3.3 million, which bear interest at the rate of 5.60%	346.7
	1,614.0
Less: Current portion	(198.2)
Debt classified as long-term	$ 1,415.8

(1) On April 18, 2014, we redeemed the remaining $198.2 million outstanding balance of the 2018 Notes.

Credit Facility As of March 31, 2014, there were $56.8 million in outstanding letters of credit and no outstanding borrowings under the Partnership's bank credit facility, leaving approximately $943.2 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 thethree months ended March 31, 2014and 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 90% 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 March 31, 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)
April 2014 - December 2016	Ethane	1,200	(MBbls)	Index	$0.2911/gal	$ (0.6)
April 2014 - December 2016	Propane	1,435	(MBbls)	Index	$1.0306/gal	(0.1)
April 2014 - March 2015	Normal Butane	60	(MBbls)	Index	$1.2592/gal	(0.1)
April 2014 - March 2015	Natural Gasoline	42	(MBbls)	Index	$1.9741/gal	(0.2)
April 2014 - March 2015	Natural Gas	940	(MMBtu/d)	$4.2201/MMBtu*	Index	0.1
						$ (0.9)

*weighted average

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

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

As of March 31, 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 0.8 million. The aggregate effect of a hypothetical 10% change, increase or decrease, in gas and NGL prices would result in a change of approximately $6.4 million in the net fair value of these contracts as of March 31, 2014.

Interest Rate Risk

We are exposed to interest rate risk on our variable rate bank credit facility. At March 31, 2014, we had no outstanding borrowings under this facility. We are not exposed to changes in interest rates with respect to our senior unsecured notes due in 2019, 2022, 2024 or 2044, as these obligations are fixed rates. The estimated fair value of our senior unsecured notes was approximately $1,664.1 million as of March 31, 2014, based on market prices of similar debt at March 31, 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 $122.5 million decrease in fair value of our senior unsecured notes at March 31, 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 (March 31, 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 March 31, 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 12, "Commitments and Contingencies," of the Notes to Condensed Consolidated Financial Statements, which is incorporated by reference herein.

Item 1A. *Risk Factors*

The following risk factors could affect our actual results and should be considered carefully when evaluating us. Other risks and uncertainties, in addition to those that are described below, may also impair our business operations. If any of the following risks occur, our business, financial condition or results of operations could be affected materially and adversely. In that case, we may be unable to make distributions to our unitholders and the trading price of our common units could decline.

These risk factors should be read in conjunction with the other detailed information concerning us set forth in our accompanying financial statements and notes and contained in "Management's Discussion and Analysis of Financial Condition and Results of Operations" detailed herein.

We are dependent on Devon for a substantial portion of the natural gas that we gather, process and transport. After the expiration of the five-year minimum volume commitments from Devon, a material decline in the volumes of natural gas that we gather, process and transport for Devon could result in a material decline in our operating results and cash available for distribution.

We are dependent on Devon for a substantial portion of our natural gas supply. In particular, Midstream Holdings relies on Devon for substantially all of its natural gas supply. For the year ended December 31, 2013, Devon represented 24.9% of our consolidated revenues. In order to minimize volumetric exposure, Midstream Holdings has received five-year minimum volume commitments from Devon at the Bridgeport processing facility, Bridgeport and East Johnson County gathering systems and the Cana and Northridge systems. After the expiration of these five-year minimum volume commitments, a material decline in the volume of natural gas that Midstream Holdings gathers and transports on its systems would result in a material decline in our combined total operating revenues and cash flow. In addition, Devon may determine in the future that drilling activity in areas of operation other than ours is strategically more attractive. A shift in Devon's focus away from our areas of operation could result in reduced throughput on our systems after the five-year minimum volume commitments expire and cause a material decline in our total operating revenues and cash flow.

Because we are substantially dependent on Devon as our primary customer and through its indirect control of our general partner, any development that materially and adversely affects Devon's operations, financial condition or market reputation could have a material and adverse impact on us. Material adverse changes at Devon could restrict our access to capital, make it more expensive to access the capital markets or increase the costs of our borrowings.

We are substantially dependent on Devon as our primary customer and through its indirect control of our general partner, and we expect to derive a substantial majority of our revenues from Devon for the foreseeable future. As a result, any event, whether in our area of operations or otherwise, that adversely affects Devon's production, financial condition, leverage, market reputation, liquidity, results of operations or cash flows may adversely affect our revenues and cash available for distribution. Accordingly, we are indirectly subject to the business risks of Devon, some of which are the following:

- potential changes in the supply of and demand for oil, natural gas and NGLs and related products and services;
- risks relating to Devon's exploration and drilling programs, including potential environmental liabilities;
- adverse effects of governmental and environmental regulation; and
- general economic and financial market conditions.

Further, we are subject to the risk of non-payment or non-performance by Devon, including with respect to our gathering and processing agreements. We cannot predict the extent to which Devon's business would be impacted if conditions in the energy industry were to deteriorate, nor can we estimate the impact such conditions would have on Devon's ability to perform under our gathering and processing agreements. Additionally, due to our relationship with Devon, our ability to access the capital markets, or the pricing or other terms of any capital markets transactions, may be adversely affected by any impairments to Devon's financial condition or adverse changes in its credit ratings. Any material limitations on our ability to access capital as a result of such adverse changes at Devon could limit our ability to obtain future financing under favorable terms, or at all, or could result in increased financing costs in the future. Similarly, material adverse changes at Devon could negatively impact our unit price, limiting our ability to raise capital through equity issuances or debt financing or our ability to engage in, expand or pursue our business activities and could also prevent us from engaging in certain transactions that might otherwise be considered beneficial to us.

Due to our lack of asset diversification, adverse developments in our gathering, transmission, processing, crude oil, condensate, natural gas and NGL services businesses would reduce our ability to make distributions to our unitholders.

We rely exclusively on the revenues generated from our gathering, transmission, processing, fractionation, crude oil, natural gas, condensate and NGL services businesses and as a result our financial condition depends upon prices of, and continued demand for, natural gas, NGLs and crude oil. Due to our lack of asset diversification, an adverse development in one of these businesses may have a significant impact on our financial condition and our ability to make distributions to our unitholders.

A significant portion of our operations are located in the Barnett Shale, making us vulnerable to risks associated with having revenue-producing operations concentrated in a limited number of geographic areas.

Our revenue-producing operations are geographically concentrated in the Barnett Shale, causing us to be disproportionally exposed to risks associated with regional factors. Specifically, our operations in the Barnett Shale accounted for approximately 28.4% of our revenues on a pro forma basis for the year ended December 31, 2013. The concentration of our operations in these regions also increases exposure to unexpected events that may occur in these regions such as natural disasters or labor difficulties. Any one of these events has the potential to have a relatively significant impact on our operations and growth plans, decrease cash flows, increase operating and capital costs and prevent development within originally anticipated time frames. Any of these risks could have a material adverse effect on our financial condition and results of operations.

We must continually compete for crude oil, condensate and natural gas supplies, and any decrease in supplies of such commodities could adversely affect our financial condition and results of operations.

In order to maintain or increase throughput levels in our natural gas gathering systems and asset utilization rates at our processing plants and to fulfill our current sales commitments, we must continually contract for new product supplies. We may not be able to obtain additional contracts for crude oil, condensate, natural gas and NGL supplies. The primary factors affecting our ability to connect new wells to our gathering facilities include our success in contracting for existing supplies that are not committed to other systems and the level of drilling activity near our gathering systems. If we are unable to maintain or increase the volumes on our systems by accessing new supplies to offset the natural decline in reserves, our business and financial results could be materially, adversely affected. In addition, our future growth will depend in part upon whether we can contract for additional supplies at a greater rate than the rate of natural decline in our current supplies.

Fluctuations in energy prices can greatly affect production rates and investments by third parties in the development of new oil, condensate and natural gas reserves. Prolonged periods of low commodity prices may put downward pressure on future drilling activity which may result in lower volumes. Tax policy changes or additional regulatory restrictions on development could also have a negative impact on drilling activity, reducing supplies of product available to our systems and assets. Additional governmental regulation of, or delays in issuance of permits for, the offshore exploration and production industry may negatively impact current and future volumes from offshore pipelines supplying our processing plants. We have no control over producers and depend on them to maintain sufficient levels of drilling activity. A material decrease in production or in the level of drilling activity in our principal geographic areas for a prolonged period, as a result of depressed commodity prices or otherwise, likely would have a material adverse effect on our results of operations and financial position.

Any decrease in the volumes that we gather, process, fractionate or transport would adversely affect our financial condition, results of operations and cash flows.

Our financial performance depends to a large extent on the volumes of natural gas, crude oil, condensate and NGLs gathered, processed, fractionated and transported on our assets. Decreases in the volumes of natural gas, crude oil, condensate and NGLs we gather, process, fractionate or transport would directly and adversely affect our revenues and results of operations. These volumes can be influenced by factors beyond our control, including:

- environmental or other governmental regulations;
- weather conditions;
- increases in storage levels of natural gas and NGLs;
- increased use of alternative energy sources;
- decreased demand for natural gas and NGLs;
- fluctuations in commodity prices, including the prices of natural gas and NGLs;
- economic conditions;
- supply disruptions;
- availability of supply connected to our systems; and
- availability and adequacy of infrastructure to gather and process supply into and out of our systems.

The volumes of natural gas, crude oil, condensate and NGLs gathered, processed, fractionated and transported on our assets also depend on the production from the regions that supply our systems. Supply of natural gas, crude oil, condensate and NGLs can be affected by many of the factors listed above, including commodity prices and weather. In order to maintain or increase throughput levels on our systems, we must obtain new sources of natural gas, crude oil, condensate and NGLs. The primary factors affecting our ability to obtain non-dedicated sources of natural gas, crude oil, condensate and NGLs include (i) the level of successful leasing, permitting and drilling activity in our areas of operation, (ii) our ability to compete for volumes from new wells and (iii) our ability to compete successfully for volumes from sources connected to other pipelines. We have no control over the level of drilling activity in our areas of operation, the amount of reserves associated with wells connected to our systems or the rate at which production from a well declines. In addition, we have no control over producers or their drilling or production decisions, which are affected by, among other things, the availability and cost of capital, levels of reserves, availability of drilling rigs and other costs of production and equipment.

Our construction of new assets may not result in revenue increases and may be subject to regulatory, environmental, political, legal and economic risks, which could adversely affect our cash flows, results of operations and financial condition.

The construction of additions or modifications to our existing systems and the construction of new midstream assets involves numerous regulatory, environmental, political and legal uncertainties beyond our control and may require the expenditure of significant amounts of capital. Financing may not be available on economically acceptable terms or at all. If we undertake these projects, we may not be able to complete them on schedule, at the budgeted cost or at all. Moreover, our revenues may not increase due to the successful construction of a particular project. For instance, if we expand a pipeline or construct a new pipeline, the construction may occur over an extended period of time, and we may not receive any material increases in revenues promptly following completion of a project or at all. Moreover, we may construct facilities to capture anticipated future production growth in a region in which such growth does not materialize. As a result, new facilities may not be able to attract enough throughput to achieve our expected investment return, which could adversely affect our results of operations and financial condition. In addition, the construction of additions to our existing gathering and processing assets will generally require us to obtain new rights-of-way and permits prior to constructing new pipelines or facilities. We may be unable to timely obtain such rights-of-way or permits to connect new product supplies to our existing gathering lines or capitalize on other attractive expansion opportunities. Additionally, it may become more expensive for us to obtain new rights-of-way or to expand or renew existing rights-of-way. If the cost of renewing or obtaining new rights-of-way increases, our cash flows could be adversely affected.

Construction of our major development projects subjects us to risks of construction delays, cost over-runs, limitations on our growth and negative effects on our operating results, liquidity and financial position.

We are engaged in the planning and construction of several major development projects, some of which will take a number of months before commercial operation, such as our Cajun-Sibon pipeline expansion project and the Bearkat processing facility project. These projects are complex and subject to a number of factors beyond our control, including delays from third-party landowners, the permitting process, complying with laws, unavailability of materials, labor disruptions, environmental hazards, financing, accidents, weather and other factors. Any delay in the completion of these projects could have a material adverse effect on our business, financial condition, results of operations and liquidity. The construction of pipelines and gathering and processing and fractionation facilities requires the expenditure of significant amounts of capital, which may exceed our estimated costs. Estimating the timing and expenditures related to these development projects is very complex and subject to variables that can significantly increase expected costs. Should the actual costs of these projects exceed our estimates, our liquidity and capital position could be adversely affected. This level of development activity requires significant effort from our management and technical personnel and places additional requirements on our financial resources and internal financial controls. We may not have the ability to attract and/or retain the necessary number of personnel with the skills required to bring complicated projects to successful conclusions.

We typically do not obtain independent evaluations of hydrocarbon reserves; therefore, volumes we service in the future could be less than we anticipate.

We typically do not obtain independent evaluations of hydrocarbon reserves connected to our gathering systems or that we otherwise service due to the unwillingness of producers to provide reserve information as well as the cost of such evaluations. Accordingly, we do not have independent estimates of total reserves serviced by our assets or the anticipated life of such reserves. If the total reserves or estimated life of the reserves is less than we anticipate and we are unable to secure additional sources, then the volumes transported on our gathering systems or that we otherwise service in the future could be less than anticipated. A decline in the volumes could have a material adverse effect on our results of operations and financial condition.

We may not be successful in balancing our purchases and sales.

We are a 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 addition, a producer could fail to deliver contracted volumes or deliver in excess of contracted volumes, or a consumer could purchase more or less than contracted volumes. Any of these actions could cause our purchases and sales not to be balanced. If our purchases and sales are not balanced, we will face increased exposure to commodity price risks and could have increased volatility in our operating income.

We have 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 our margins or even result in losses. For example, we are a party to one contract with a term to 2019 to supply approximately 150,000 MMBtu/d of gas. We buy gas for this contract on several different production-area indices on our North Texas Pipeline and sell the gas into a different market area index. We realize a loss on the delivery of gas under this contract each month based on current prices. The balance sheet as of December 31, 2013 reflects a liability of $100.9 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.

Our profitability is dependent upon prices and market demand for oil, condensate, natural gas and NGLs, which are beyond our control and have been volatile.

We are subject to significant risks due to fluctuations in commodity prices. We are directly exposed to these risks primarily in the gas processing component of our business. For the year ended December 31, 2013, approximately 3.5% of our total gross operating margin, on a pro forma basis giving effect to the business combination was generated under percent of liquids contracts. Under these contracts we receive a fee in the form of a percentage of the liquids recovered and the producer bears all the cost of the natural gas shrink. Accordingly, our revenues under these contracts are directly impacted by the market price of NGLs.

We also realize processing gross operating margins under processing margin (margin) contracts. For the year ended December 31, 2013 approximately 2.2% of our total gross operating margin, on a pro forma basis giving effect to the business combination was generated under processing margin contracts. We have a number of processing margin contracts for activities at our Plaquemine, Gibson and Pelican processing plants. 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 can be greatly reduced or eliminated during periods of high natural gas prices relative to liquids prices. Although we do not currently have any processing margin contracts for our Blue Water and Eunice plants, we do have the opportunity to process liquids from wet gas flowing on the pipelines connected to these plants, as well as our other processing plants, when market pricing is favorable. Our Eunice and Blue Water plants are not profitable to operate unless market pricing is very favorable.

We are also indirectly exposed to commodity prices due to the negative impacts on production and the development of production of oil, condensate, natural gas and NGLs connected to or near our assets and on our margins for transportation between certain market centers. Low prices for these products will reduce the demand for our services and volumes on our systems.

In the past, the prices of oil, condensate, natural gas and NGLs have been extremely volatile, and we expect this volatility to continue. For example, crude oil prices (based on the NYMEX futures daily close prices for the prompt month) in 2013 ranged from a high of $110.53 per Bbl in September 2013 to a low of $86.68 per Bbl in April 2013. Weighted average NGL prices in 2013 (based on the Oil Price Information Service (OPIS) Napoleonville daily average spot liquids prices) ranged from a high of $1.09 per gallon in September 2013 to a low of $0.84 per gallon in June 2013. Natural gas prices (based on Gas Daily Henry Hub closing prices) during 2013 ranged from a high of $4.52 per MMBtu in December 2013 to a low of $3.08 per MMBtu in January 2013.

The markets and prices for oil, condensate, natural gas and NGLs depend upon factors beyond our control. These factors include the supply and demand for oil, condensate, natural gas and NGLs, which fluctuate with changes in market and economic conditions and other factors, including:

- the impact of weather on the demand for oil and natural gas;
- the level of domestic oil, condensate and natural gas production;
- technology, including improved production techniques (particularly with respect to shale development);
- the level of domestic industrial and manufacturing activity;
- the availability of imported oil, natural gas and NGLs;
- international demand for oil and NGLs;
- actions taken by foreign oil and gas producing nations;
- the availability of local, intrastate and interstate transportation systems;
- the availability of downstream NGL fractionation facilities;
- the availability and marketing of competitive fuels;
- the impact of energy conservation efforts; and
- the extent of governmental regulation and taxation, including the regulation of "greenhouse gases."

Changes in commodity prices may also indirectly impact our profitability by influencing drilling activity and well operations, and thus the volume of gas, crude oil and condensate we gather and process. The volatility in commodity prices may cause our gross operating margin and cash flows to vary widely from period to period. Our hedging strategies may not be sufficient to offset price volatility risk and, in any event, do not cover all of our throughput volumes. Moreover, hedges are subject to inherent risks, which we describe in "Item 3. Quantitative and Qualitative Disclosures About Market Risk" herein and in "Item 7A. Quantitative and Qualitative Disclosure about Market Risk" in our Annual Report on Form 10-K for the year ended December 31, 2013. Our use of derivative financial instruments does not eliminate our exposure to fluctuations in commodity prices and interest rates and has in the past and could in the future result in financial losses or reduce our income.

If third-party pipelines or other midstream facilities interconnected to our gathering or transportation systems become partially or fully unavailable, or if the volumes we gather, process or transport do not meet the natural gas quality requirements of such pipelines or facilities, our gross operating margin and cash flow could be adversely affected.

Our gathering, processing and transportation assets connect to other pipelines or facilities owned and operated by unaffiliated third parties, including Atmos Energy, Enable Midstream Partners, ONEOK Partners and others. The continuing operation of, and our continuing access to, such third-party pipelines, processing facilities and other midstream facilities is not within our control. These pipelines, plants and other midstream facilities may become unavailable because of testing, turnarounds, line repair, maintenance, reduced operating pressure, lack of operating capacity, regulatory requirements and curtailments of receipt or deliveries due to insufficient capacity or because of damage from severe weather conditions or other operational issues. In addition, if our costs to access and transport on these third-party pipelines significantly increase, our profitability could be reduced. If any such increase in costs occurs, if any of these pipelines or other midstream facilities become unable to receive, transport or process natural gas, or if the volumes we gather or transport do not meet the natural gas quality requirements of such pipelines or facilities, our operating margin and cash flow could be adversely affected.

Our debt levels could limit our flexibility and adversely affect our financial health or limit our flexibility to obtain financing and to pursue other business opportunities.

We continue to have the ability to incur debt, subject to limitations in our credit facility. Our level of indebtedness could have important consequences to us, including the following:

- our ability to obtain additional financing, if necessary, for working capital, capital expenditures, acquisitions or other purposes may be impaired or such financing may not be available on favorable terms;
- our funds available for operations, future business opportunities and distributions to unitholders will be reduced by that portion of our cash flows required to make interest payments on our debt;
- our debt level will make us more vulnerable to general adverse economic and industry conditions; and
- limit our flexibility in planning for, or reacting to, changes in our business and the industry in which we operate.

In addition, our ability to make scheduled payments or to refinance our obligations depends on our successful financial and operating performance, which will be affected by prevailing economic conditions and financial, business, regulatory and other factors, many of which are beyond our control. If our cash flow and capital resources are insufficient to fund our debt service obligations, we may be forced to take actions such as reducing distributions, reducing or delaying our business activities, acquisitions, investments or capital expenditures, selling assets, restructuring or refinancing our debt or seeking additional equity capital. We may not be able to effect any of these actions on satisfactory terms or at all.

A default under ENLC's credit facility could have an adverse effect on the price of our common units and could result in a change of control of our general partner.

ENLC has entered into a credit facility that is secured by, among other things, a first priority lien on 16,414,830 of our common units and the 100% membership interest in our general partner indirectly held by ENLC, along with ENLC's 50% limited partner interest in Midstream Holdings. Although we are not a party to this credit facility, if a default under such credit facility were to occur, the lenders could foreclose on the pledged security interests. Any such foreclosure on our common units could have an adverse effect on the market price of our common units. In addition, any foreclosure on ENLC's interest in the general partner would allow the new owner of our general partner to replace the board of directors and officers of our general partner with its own choices and to control the decisions taken by the board of directors and officers. Moreover, any change of control of our general partner (i) would permit the lenders under our credit facility to declare all amounts thereunder immediately due and payable and (ii) may permit the holders of our 7.125% Senior Notes due 2022 to require us to repurchase such notes. If any such event occurs, we may be required to refinance our debt on unfavorable terms, which could negatively impact our results of operations and our ability to make distributions to our unitholders.

We are vulnerable to operational, regulatory and other risks due to our concentration of assets in south Louisiana and the Gulf of Mexico, including the effects of adverse weather conditions such as hurricanes.

Our operations and revenues will be significantly impacted by conditions in south Louisiana and the Gulf of Mexico because we have a significant portion of our assets located in these two areas. Our concentration of activity in Louisiana and the Gulf of Mexico makes us more vulnerable than many of our competitors to the risks associated with these areas, including:

- adverse weather conditions, including hurricanes and tropical storms;
- delays or decreases in production, the availability of equipment, facilities or services; and
- changes in the regulatory environment.

Because a significant portion of our operations could experience the same condition at the same time, these conditions could have a relatively greater impact on our results of operations than they might have on other midstream companies that have operations in more diversified geographic areas.

A reduction in demand for NGL products by the petrochemical, refining or other industries or by the fuel markets could materially adversely affect our results of operations and financial condition.

The NGL products we produce have a variety of applications, including as heating fuels, petrochemical feedstocks and refining blend stocks. A reduction in demand for NGL products, whether because of general or industry specific economic conditions, new government regulations, global competition, reduced demand by consumers for products made with NGL products (for example, reduced petrochemical demand observed due to lower activity in the automobile and construction industries), increased competition from petroleum-based feedstocks due to pricing differences, mild winter weather for some NGL applications or other reasons could result in a decline in the volume of NGL products we handle or reduce the fees we charge for our services. Our NGL products and the demand for these products are affected as follows:

- *Ethane.* Ethane is typically supplied as purity ethane or as part of ethane-propane mix. Ethane is primarily used in the petrochemical industry as feedstock for ethylene, one of the basic building blocks for a wide range of plastics and other chemical products. Although ethane is typically extracted as part of the mixed NGL stream at gas processing plants, if natural gas prices increase significantly in relation to NGL product prices or if the demand for ethylene falls, it may be more profitable for natural gas processors to leave the ethane in the natural gas stream thereby reducing the volume of NGLs delivered for fractionation and marketing.
- *Propane.* Propane is used as a petrochemical feedstock in the production of ethylene and propylene, as a heating, engine and industrial fuel, and in agricultural applications such as crop drying. Changes in demand for ethylene and propylene could adversely affect demand for propane. The demand for propane as a heating fuel is significantly affected by weather conditions. The volume of propane sold is at its highest during the six-month peak heating season of October through March. Demand for our propane may be reduced during periods of warmer-than-normal weather.
- *Normal Butane.* Normal butane is used in the production of isobutane, as a refined product blending component, as a fuel gas, and in the production of ethylene and propylene. Changes in the composition of refined products resulting from governmental regulation, changes in feedstocks, products and economics, demand for heating fuel and for ethylene and propylene could adversely affect demand for normal butane.
- *Isobutane.* Isobutane is predominantly used in refineries to produce alkylates to enhance octane levels. Accordingly, any action that reduces demand for motor gasoline or demand for isobutane to produce alkylates for octane enhancement might reduce demand for isobutane.
- *Natural Gasoline.* Natural gasoline is used as a blending component for certain refined products and as a feedstock used in the production of ethylene and propylene. Changes in the mandated composition resulting from governmental regulation of motor gasoline and in demand for ethylene and propylene could adversely affect demand for natural gasoline.

NGLs and products produced from NGLs also compete with global markets. Any reduced demand for ethane, propane, normal butane, isobutane or natural gasoline in the markets we access for any of the reasons stated above could adversely affect demand for the services we provide as well as NGL prices, which would negatively impact our results of operations and financial condition.

We expect to encounter significant competition in any new geographic areas into which we seek to expand, and our ability to enter such markets may be limited.

If we expand our operations into new geographic areas, we expect to encounter significant competition for natural gas, condensate, NGLs and crude oil supplies and markets. Competitors in these new markets will include companies larger than us, which have both lower cost of capital and greater geographic coverage, as well as smaller companies, which have lower total cost structures. As a result, we may not be able to successfully develop acquired assets and markets located in new geographic areas and our results of operations could be adversely affected.

With completion of the business combination, we significantly increased the size of our business and expanded our business into geographic regions in which the former Crosstex Energy, L.P. did not previously operate, including the Cana and Arkoma Woodford Shales in Oklahoma. In order to operate effectively in these new regions, we need to understand the local market and regulatory environment and identify and retain certain employees from Devon who are familiar with these markets. If we are not successful in retaining these employees or operating in these new geographic areas, we may not be able to compete effectively in the new markets or fully realize the expected benefits of the business combination.

The terms of our credit facility and indentures may restrict our current and future operations, particularly our ability to respond to changes in business or to take certain actions.

Our credit agreement and the indentures governing our senior notes contain, and any future indebtedness we incur will likely contain, a number of restrictive covenants that impose significant operating and financial restrictions, including restrictions on our ability to engage in acts that may be in our best long-term interest. One or more of these agreements include covenants that, among other things, restrict our ability to:

- incur or guarantee additional indebtedness or issue preferred stock;
- pay dividends on our equity securities or redeem, repurchase or retire our equity securities or subordinated indebtedness;
- make investments;
- pay dividends or other distributions by our subsidiaries;
- engage in transactions with our affiliates;
- sell assets, including equity securities of our subsidiaries;
- consolidate or merge;
- incur liens;
- prepay, redeem and repurchase subordinated debt;
- make certain acquisitions;
- transfer assets;
- enter into sale and lease back transactions; and
- change business activities we conduct.

In addition, our credit facility requires us to satisfy and maintain a specified financial ratio. Our ability to meet that financial ratio can be affected by events beyond our control, and we cannot assure you that we will continue to meet that ratio.

A breach of any of these covenants could result in an event of default under our credit facility and indentures. Upon the occurrence of such an event of default, all amounts outstanding under the applicable debt agreements could be declared to be immediately due and payable and all applicable commitments to extend further credit could be terminated. If indebtedness under our credit facility or indentures is accelerated, there can be no assurance that we will have sufficient assets to repay the indebtedness. The operating and financial restrictions and covenants in these debt agreements and any future financing agreements may adversely affect our ability to finance future operations or capital needs or to engage in other business activities.

We do not own most of the land on which our pipelines and compression facilities are located, which could disrupt our operations.

We do not own most of the land on which our pipelines and compression facilities are located, and we are therefore subject to the possibility of more onerous terms and/or increased costs to retain necessary land use if we do not have valid rights-of-way or leases or if such rights-of-way or leases lapse or terminate. We sometimes obtain the rights to land owned by third parties and governmental agencies for a specific period of time. Our loss of these rights, through our inability to renew right-of-way contracts, leases or otherwise, could cause us to cease operations on the affected land, increase costs related to continuing operations elsewhere and reduce our revenue.

We offer pipeline, truck, rail and barge services. Significant delays, inclement weather or increased costs affecting these transportation methods could materially affect our operations and earnings.

We offer pipeline, truck, rail and barge services. The costs of conducting these services could be negatively affected by factors outside of our control, including rail service interruptions, new laws and regulations, rate increases, tariffs, rising fuel costs or capacity constraints. Inclement weather, including hurricanes, tornadoes, snow, ice and other weather events, can negatively impact our distribution network. In addition, rail, truck or barge accidents involving the transportation of hazardous materials could result in significant claims arising from personal injury, property damage and environmental penalties and remediation.

We could experience increased severity or frequency of trucking accidents and other claims.

Potential liability associated with accidents in the trucking industry is severe and occurrences are unpredictable. A material increase in the frequency or severity of accidents or workers' compensation claims or the unfavorable development of existing claims could be expected to materially adversely affect our results of operations. In the event that accidents occur, we may be unable to obtain desired contractual indemnities, and our insurance may be inadequate in certain cases. The occurrence of an event not fully insured or indemnified against, or the failure or inability of a customer or insurer to meet its indemnification or insurance obligations, could result in substantial losses.

Changes in trucking regulations may increase our costs and negatively impact our results of operations.

Our trucking services are subject to regulation as a motor carrier by the United States Department of Transportation ("DOT") and by various state agencies, whose regulations include certain permit requirements of state highway and safety authorities. These regulatory authorities exercise broad powers over our trucking operations, generally governing such matters as the authorization to engage in motor carrier operations, safety, equipment testing and specifications and insurance requirements. There are additional regulations specifically relating to the trucking industry, including testing and specification of equipment and product handling requirements. The trucking industry is subject to possible regulatory and legislative changes that may impact our operations and affect the economics of the industry by requiring changes in operating practices or by changing the demand for or the cost of providing trucking services. Some of these possible changes include increasingly stringent fuel emission limits, changes in the regulations that govern the amount of time a driver may drive or work in any specific period, limits on vehicle weight and size and other matters, including safety requirements.

If we do not make acquisitions on economically acceptable terms or efficiently and effectively integrate the acquired assets with our asset base, our future growth will be limited.

Our ability to grow depends, in part, on our ability to make acquisitions that result in an increase in cash generated from operations on a per unit basis. If we are unable to make accretive acquisitions either because we are (1) unable to identify attractive acquisition candidates or negotiate acceptable purchase contracts with them, (2) unable to obtain financing for these acquisitions on economically acceptable terms or at all or (3) outbid by competitors, then our future growth and our ability to increase distributions will be limited.

From time to time, we may evaluate and seek to acquire assets or businesses that we believe complement our existing business and related assets. We may acquire assets or businesses that we plan to use in a manner materially different from their prior owner's use. Any acquisition involves potential risks, including:

- the inability to integrate the operations of recently acquired businesses or assets, especially if the assets acquired are in a new business segment or geographic area;
- the diversion of management's attention from other business concerns;
- the failure to realize expected volumes, revenues, profitability or growth;
- the failure to realize any expected synergies and cost savings;
- the coordination of geographically disparate organizations, systems and facilities;
- the assumption of unknown liabilities;
- the loss of customers or key employees from the acquired businesses;
- a significant increase in our indebtedness; and
- potential environmental or regulatory liabilities and title problems.

Management's assessment of these risks is inexact and may not reveal or resolve all existing or potential problems associated with an acquisition. Realization of any of these risks could adversely affect our operations and cash flows. If we consummate any future acquisition, our capitalization and results of operations may change significantly, and you will not have the opportunity to evaluate the economic, financial and other relevant information that we will consider in determining the application of these funds and other resources.

We may not be able to retain existing customers or acquire new customers, which would reduce our revenues and limit our future profitability.

The renewal or replacement of existing contracts with our customers at rates sufficient to maintain current revenues and cash flows depends on a number of factors beyond our control, including competition from other midstream service providers, and the price of, and demand for, crude oil, condensate, NGLs and natural gas in the markets we serve. The inability of our management to renew or replace our current contracts as they expire and to respond appropriately to changing market conditions could have a negative effect on our profitability.

In particular, our ability to renew or replace our existing contracts with industrial end-users and utilities impacts our profitability. For the year ended December 31, 2013, approximately 51.0% of our sales of gas that was transported using our physical facilities were to industrial end-users and utilities, on a pro forma basis giving effect to the business combination. As a consequence of the increase in competition in the industry and volatility of natural gas prices, end-users and utilities may be reluctant to enter into long-term purchase contracts. Many end-users purchase natural gas from more than one natural gas company and have the ability to change providers at any time. Some of these end-users also have the ability to switch between gas and alternate fuels in response to relative price fluctuations in the market. Because there are numerous companies of greatly varying size and financial capacity that compete with us in the marketing of natural gas, we often compete in the end-user and utilities markets primarily on the basis of price.

We are exposed to the credit risk of our customers and counterparties, and a general increase in the nonpayment and nonperformance by our customers could have an adverse effect on our financial condition and results of operations.

Risks of nonpayment and nonperformance by our customers are a major concern in our business. We are subject to risks of loss resulting from nonpayment or nonperformance by our customers and other counterparties, such as our lenders and hedging counterparties. Any increase in the nonpayment and nonperformance by our customers could adversely affect our results of operations and reduce our ability to make distributions to our unitholders.

Increased regulation of hydraulic fracturing could result in reductions or delays in natural gas production by our customers, which could adversely impact our revenues.

A portion of our suppliers' and customers' natural gas production is developed from unconventional sources, such as deep gas shales, that require hydraulic fracturing as part of the completion process. Hydraulic fracturing involves the injection of water, sand and chemicals under pressure into the formation to stimulate gas production. Hydraulic fracturing activities are generally regulated by state oil and gas commissions; however, in February 2014 the Environmental Protection Agency (the"EPA") issued an interpretative memorandum and technical recommendations to EPA Regions and to State and Tribal Underground Injection Control (UIC) Program directors concerning the EPA's interpretation that hydraulic fracturing activities involving diesel are subject to the permitting requirements of the federal Safe Drinking Water Act UIC program. The EPA also released permitting guidance for hydraulic fracturing activities involving diesel for use by the EPA in states where the EPA is the UIC permitting authority. In addition, legislation has been proposed, but not passed that would provide for federal regulation of hydraulic fracturing and require disclosure of the chemicals used in the hydraulic-fracturing process. State legislatures and agencies are also enacting legislation and promulgating rules to regulate hydraulic fracturing and require disclosure of hydraulic fracturing chemicals.

There are certain governmental reviews either underway or being proposed that focus on environmental aspects of hydraulic fracturing practices. The White House Council on Environmental Quality is coordinating an administration-wide review of hydraulic fracturing practices, and a committee of the United States House of Representatives has conducted an investigation of hydraulic fracturing practices. In addition, the EPA is conducting a study of the potential environmental effects of hydraulic fracturing on drinking water and groundwater and has initiated plans to promulgate regulations controlling wastewater disposal associated with hydraulic fracturing and shale gas development. In addition to the EPA, other federal agencies are analyzing, or have been requested to review, a variety of environmental issues associated with hydraulic fracturing. These on-going or proposed studies, depending on their degree of pursuit and any meaningful results obtained, could spur initiatives to further regulate hydraulic fracturing under the Safe Drinking Water Act, the Toxic Substances Control Act, or other statutory and/or regulatory mechanisms. President Obama created the Interagency Working Group on Unconventional Natural Gas and Oil by Executive Order on April 13, 2012, which is charged with coordinating and aligning federal agency research and scientific studies on unconventional natural gas and oil resources.

We cannot predict whether any additional legislation or regulations will be enacted and, if so, what the provisions would be. If additional levels of regulation and permits were required through the adoption of new laws and regulations at the federal or state level, that could lead to delays, increased operating costs and process prohibitions for our suppliers and customers that could reduce the volumes of natural gas that move through our gathering systems which could materially adversely affect our revenue and results of operations.

Transportation on certain of our natural gas pipelines is subject to federal and state rate and service regulation, which could limit the revenues we collect from our customers and adversely affect the cash available for distribution to our unitholders. The imposition of regulation on our currently unregulated natural gas pipelines also could increase our operating costs and adversely affect the cash available for distribution to our unitholders.

The rates, terms and conditions of service under which we transport natural gas in our pipeline systems in interstate commerce are subject to regulation of the Federal Energy Regulatory Commission ("FERC") under Section 311 of the Natural Gas Policy Act and the rules and regulations promulgated under that statute. Under these regulations, we are required to justify our rates for interstate transportation service on a cost-of-service basis every five years. Our intrastate natural gas pipeline operations are subject to regulation by various agencies of the states in which they are located. Should FERC or any of these state agencies determine that our rates for Section 311 transportation service or intrastate transportation service should be lowered, our business could be adversely affected.

Our natural gas gathering and processing activities generally are exempt from FERC regulation under the Natural Gas Act. However, the distinction between FERC-regulated transmission services and federally unregulated gathering services is the subject of substantial, on-going litigation, so the classification and regulation of our gathering facilities are subject to change based on future determinations by FERC and the courts. Natural gas gathering may receive greater regulatory scrutiny at both the state and federal levels since FERC has less extensively regulated the gathering activities of interstate pipeline transmission companies and a number of such companies have transferred gathering facilities to unregulated affiliates. Our gathering operations also may be or become subject to safety and operational regulations relating to the design, installation, testing, construction, operation, replacement and management of gathering facilities. Additional rules and legislation pertaining to these matters are considered or adopted from time to time. We cannot predict what effect, if any, such changes might have on our operations, but the industry could be required to incur additional capital expenditures and increased costs depending on future legislative and regulatory changes.

Other state and local regulations also affect our business. We are subject to some ratable take and common purchaser statutes in the states where we operate. Ratable take statutes generally require gatherers to take, without undue discrimination, natural gas production that may be tendered to the gatherer for handling. Similarly, common purchaser statutes generally require gatherers to purchase without undue discrimination as to source of supply or producer. These statutes have the effect of restricting our right as an owner of gathering facilities to decide with whom we contract to purchase or transport natural gas. Federal law leaves any economic regulation of natural gas gathering to the states, and some of the states in which we operate have adopted complaint-based or other limited economic regulation of natural gas gathering activities. States in which we operate that have adopted some form of complaint-based regulation, like Texas, generally allow natural gas producers and shippers to file complaints with state regulators in an effort to resolve grievances relating to natural gas gathering access and rate discrimination.

Transportation on our liquids pipelines is subject to federal rate and service regulation, which could limit the revenues we collect from our customers and adversely affect the cash available for distribution to our unitholders.

Our liquids transportation pipelines in the Ohio River Valley and the Cajun-Sibon NGL pipeline, which went into service in November 2013, are subject to regulation by FERC under the ICA, the Energy Policy Act of 1992 and the rules and regulations promulgated under those laws. The ICA and its implementing regulations require that tariff rates and terms and conditions of service for interstate service on liquids pipelines be just, reasonable and not unduly discriminatory or preferential. The ICA also requires that such rates and terms and conditions be set forth in tariffs filed with FERC. The ICA permits interested persons to challenge proposed new or changed rates and authorizes FERC to suspend the effectiveness of such rates for up to seven months and investigate such rates. If, upon completion of an investigation, FERC finds that the new or changed rates are unlawful, it is authorized to require the pipeline to refund revenues collected in excess of the just and reasonable rates during the term of the investigation. FERC may also investigate, upon complaint or on its own motion, rates that are already in effect and may order a carrier to change its rates prospectively. Under certain circumstances, FERC could limit our ability to set rates based on our costs or could order us to reduce our rates and could require the payment of reparations to complaining shippers for up to two years prior to the date of the complaint. FERC also has the authority to change our terms and conditions of service if it determines that they are unjust and unreasonable or unduly discriminatory or preferential.

As we acquire, construct and operate new liquids assets and expand our liquids transportation business, the classification and regulation of our liquids transportation services are subject to ongoing assessment and change based on the services we provide and determinations by FERC and the courts. Such changes may subject additional services we provide to regulation by FERC, which could increase our operating costs, decrease our rates and adversely affect our business.

We may incur significant costs and liabilities resulting from compliance with pipeline safety regulations.

The states in which we conduct operations administer federal pipeline safety standards under the Natural Gas Pipeline Safety Act of 1968. These standards only apply to certain natural gas gathering lines based on the gathering line’s operating pressure and proximity to people. Because of their pressure and location, substantial portions of our gathering facilities are not regulated under that statute. The gathering line exemptions, however, may be revised in the future and place more of our gathering facilities under jurisdiction of the DOT. Nonetheless, our natural gas transmission pipelines are subject to regulation by the DOT. In response to pipeline accidents in other parts of the country, Congress and the DOT, through the Pipeline and Hazardous Materials Safety Administration, or PHMSA, have passed or are considering heightened pipeline safety requirements that may be applicable to gathering lines. As a result, our pipeline facilities are subject to the Pipeline Safety, Regulatory Certainty and Job Creation Act of 2011, which reauthorized funding for federal safety programs through 2015, increased penalties for safety violations, established additional safety requirements for newly constructed pipelines and required studies of certain safety issues that could result in the adoption of new regulatory requirements for existing pipelines.

At the state level, several states have passed legislation or promulgated rulemaking addressing pipeline safety. Compliance with pipeline integrity and other pipeline safety regulations issued by DOT or those issued by the Texas Railroad Commission, or TRRC, could result in substantial expenditures for testing, repairs and replacement. TRRC regulations require periodic testing of all intrastate pipelines meeting certain size and location requirements. Our costs relating to compliance with the required testing under the TRRC regulations were approximately at $7.0 million, $8.6 million, and $7.9 million for the years ended December 31, 2013, 2012 and 2011, respectively. We expect the costs for compliance with TRRC and DOT regulations to be approximately $5.0 million during 2014. If our pipelines fail to meet the safety standards mandated by the TRRC or the DOT regulations, then we may be required to repair or replace sections of such pipelines or operate the pipelines at a reduced maximum allowable operating pressure, the cost of which cannot be estimated at this time.

In addition, our liquids transportation pipelines are subject to regulation by the DOT, through PHMSA, pursuant to the Hazardous Liquids Pipeline Safety Act of 1979, as amended by the Pipeline Safety Improvement Act of 2002, and reauthorized and amended by the Pipeline Inspection, Protection, Enforcement and Safety Act of 2006. PHMSA has adopted regulations requiring hazardous liquid pipeline operators to develop and implement integrity management programs for pipeline segments that, in the event of a leak or rupture, could affect "high consequence areas," such as high population areas, areas that are sources of drinking water, ecological resource areas that are unusually sensitive to environmental damage from a pipeline release and commercially navigable waterways, unless the operator effectively demonstrates by risk assessment that the pipeline could not affect the area.

Due to the possibility of new or amended laws and regulations or reinterpretation of existing laws and regulations, there can be no assurance that future compliance with the PHMSA or state requirements will not have a material adverse effect on our results of operations or financial positions. As our operations continue to expand into and around urban or more populated areas, such as the Barnett Shale, we may incur additional expenses to mitigate noise, odor and light that may be emitted in our operations and expenses related to the appearance of our facilities. Municipal and other local or state regulations are imposing various obligations including, among other things, regulating the location of our facilities, imposing limitations on the noise levels of our facilities and requiring certain other improvements that increase the cost of our facilities. We are also subject to claims by neighboring landowners for nuisance related to the construction and operation of our facilities, which could subject us to damages for declines in neighboring property values due to our construction and operation of facilities.

Failure to comply with existing or new environmental laws or regulations or an accidental release of hazardous substances, hydrocarbons or wastes into the environment may cause us to incur significant costs and liabilities.

Many of the operations and activities of our gathering systems, processing plants, fractionators, brine disposal operations and other facilities are subject to significant federal, state and local environmental laws and regulations. The obligations imposed by these laws and regulations include obligations related to air emissions and discharge of pollutants from our facilities and the cleanup of hazardous substances and other wastes that may have been released at properties currently or previously owned or operated by us or locations to which we have sent wastes for treatment or disposal. Various governmental authorities have the power to enforce compliance with these laws and regulations and the permits issued under them, and violators are subject to administrative, civil and criminal penalties, including civil fines, injunctions or both. Strict, joint and several liability may be incurred under these laws and regulations for the remediation of contaminated areas. Private parties, including the owners of properties near our facilities or upon or through which our gathering systems traverse, may also have the right to pursue legal actions to enforce compliance as well as to seek damages for non-compliance with environmental laws and regulations for releases of contaminants or for personal injury or property damage.

There is inherent risk of the incurrence of significant environmental costs and liabilities in our business due to our handling of natural gas, crude oil and other petroleum substances, our brine disposal operations, air emissions related to our operations, historical industry operations, waste disposal practices and the prior use of natural gas flow meters containing mercury. For example, we operate brine disposal wells in Ohio and West Virginia and may gather brine from surrounding states. These wells are regulated under the federal Safe Drinking Water Act (SDWA) as Class II wells and under state laws. State laws and regulations that govern these operations can be more stringent than the federal SDWA, such as the Ohio Department of Natural Resources rules which took effect October 1, 2012. These rules imposed new, more stringent environmentally responsible standards for the permitting and operating of brine disposal wells, including extensive review of geologic data and use of state of the art technology. They apply to new disposal wells and, as applicable, to existing wells. The Ohio Department of Natural Resources also imposes requirements on the transportation and disposal of brine. In addition, the possibility exists that stricter laws, regulations or enforcement policies could significantly increase our compliance costs and the cost of any remediation that may become necessary. We may incur material environmental costs and liabilities. Furthermore, our insurance may not provide sufficient coverage in the event an environmental claim is made against us.

In addition, state and federal regulatory agencies recently have focused on a possible connection between the operation of injection wells used for oil and gas waste waters and an observed increase in minor seismic activity and tremors. When caused by human activity, such events are called induced seismicity. Regulatory agencies are continuing to study possible linkage between injection activity and induced seismicity. To the extent these studies result in additional regulation of injection wells, such regulations could impose additional regulations, costs and restrictions on our brine disposal operations.

Our business may be adversely affected by increased costs due to stricter pollution control requirements or liabilities resulting from non-compliance with required operating or other regulatory permits. New environmental laws or regulations, including, for example, legislation relating to the control of greenhouse gas emissions, or changes in existing environmental laws or regulations might adversely affect our products and activities, including processing, storage and transportation, as well as waste management and air emissions. Federal and state agencies could also impose additional safety requirements, any of which could affect our profitability. Changes in laws or regulations could also limit our production or the operation of our assets or adversely affect our ability to comply with applicable legal requirements or the demand for crude oil, brine disposal services or natural gas, which could adversely affect our business and our profitability.

Recently finalized rules under the Clean Air Act imposing more stringent requirements on the oil and gas industry could cause our customers and us to incur increased capital expenditures and operating costs as well as reduce the demand for our services.

On April 17, 2012, the EPA issued final rules under the Clean Air Act that became effective on October 15, 2012. Among other things, these rules require additional emissions controls for natural gas and NGLs production, including New Source Performance Standards to address emissions of sulfur dioxide and volatile organic compounds ("VOCs") and a separate set of emission standards to address hazardous air pollutants frequently associated with such production activities. The final regulations require, among other things, the reduction of VOC emissions from natural gas wells through the use of reduced emission completions or "green completions" on all hydraulically fractured wells constructed or refractured after January 1, 2015. Moreover, these rules establish specific requirements regarding emissions from compressors and controllers at natural gas gathering and boosting stations and processing plants together with dehydrators and storage tanks at natural gas processing plants, compressor stations and gathering and boosting stations. The rules also establish new requirements for leak detection and repair of leaks at natural gas processing plants that exceed 500 parts per million in concentration. These regulations could require a number of modifications to our operations and our natural gas exploration and production suppliers' and customers' operations, including the installation of new equipment, which could result in significant costs, including increased capital expenditures and operating costs. The incurrence of such expenditures and costs by our suppliers and customers could result in reduced production by those suppliers and customers and thus translate into reduced demand for our services. The rules are subject to an ongoing legal challenge brought by various parties, including environmental groups and industry, and the EPA has indicated that it may revise the rules. Any such revisions could affect our operations, as well as the operations of our suppliers and customers.

Climate change legislation and regulatory initiatives could result in increased operating costs and reduced demand for the natural gas and NGL services we provide.

On December 15, 2009, the EPA published its findings that emissions of carbon dioxide, methane and other greenhouse gases ("GHGs") present an endangerment to public health and the environment because emissions of such gases are, according to the EPA, contributing to warming of the earth's atmosphere and other climatic changes. These findings allowed the EPA to proceed with the adoption and implementation of regulations restricting emissions of GHGs under existing provisions of the federal Clean Air Act. Since 2011, the EPA has required stationary sources that emit GHGs above regulatory and statutory thresholds to obtain a Prevention of Significant Deterioration permit. Moreover, on October 30, 2009, the EPA published a "Mandatory Reporting of Greenhouse Gases" final rule that established a comprehensive scheme requiring operators of stationary sources emitting more than established annual thresholds of GHGs to inventory and report their GHG emissions annually on a facility-by-facility basis. The Mandatory Reporting Rule was expanded by a rule promulgated on November 30, 2010 to include owners and operators of onshore oil and natural gas production, processing, transmission, storage and distribution facilities. Reporting emissions from such onshore activities is required on an annual basis. The first reports were due in 2012 for emissions occurring in 2011. Additionally, the EPA has proposed to regulate greenhouse gas emissions from certain electric generating units under the Clean Air Act's New Source Performance Standards ("NSPS") program. The EPA may propose to regulate additional source categories under the NSPS program in the future.

In addition, the U.S. Congress has from time to time considered legislation to reduce emissions of GHGs, and almost half of the states have already taken legal measures to reduce emissions of GHGs, primarily through the planned development of GHG emission inventories and/or regional GHG cap and trade programs. Most of these cap and trade programs work by requiring either major sources of emissions, such as electric power plants, or major producers of fuels, such as refineries and NGL fractionation plants, to acquire and surrender emission allowances with the number of allowances available for purchase reduced each year until the overall GHG emission reduction goal is achieved. The adoption of legislation or regulations imposing reporting or permitting obligations on, or limiting emissions of GHGs from, our equipment and operations could require us to incur additional costs to reduce emissions of GHGs associated with our operations, could adversely affect our performance of operations in the absence of any permits that may be required to regulate emission of GHGs or could adversely affect demand for the natural gas we gather, process or otherwise handle in connection with our services.

Our business involves many hazards and operational risks, some of which may not be fully covered by insurance.

Our operations are subject to the many hazards inherent in the gathering, compressing, processing, transporting, fractionating, disposing and storage of natural gas, NGLs, condensate, crude oil and brine, including:

- damage to pipelines, related equipment and surrounding properties caused by hurricanes, floods, fires and other natural disasters and acts of terrorism;
- inadvertent damage from construction and farm equipment;
- leaks of natural gas, NGLs, crude oil and other hydrocarbons;
- induced seismicity;
- rail accidents, barge accidents and truck accidents; and
- fires and explosions.

These risks could result in substantial losses due to personal injury and/or loss of life, severe damage to and destruction of property and equipment and pollution or other environmental damage and may result in curtailment or suspension of our related operations. We are not fully insured against all risks incident to our business. In accordance with typical industry practice, we do not have business interruption insurance or any property insurance on any of our underground pipeline systems that would cover damage to the pipelines. We are not insured against all environmental accidents that might occur, other than those considered to be sudden and accidental. If a significant accident or event occurs that is not fully insured, it could adversely affect our operations and financial condition.

The adoption of derivatives legislation by the United States Congress and promulgation of related regulations could have an adverse effect on our ability to hedge risks associated with our business.

Comprehensive financial reform legislation was signed into law by the President on July 21, 2010. The legislation calls for the CFTC to regulate certain markets for derivative products, including 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 the mandates in the 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 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 to lower commodity prices. Any of these consequences could have a material, adverse effect on us, our financial condition and our results of operations.

Our use of derivative financial instruments does not eliminate our exposure to fluctuations in commodity prices and interest rates and has in the past and could in the future result in financial losses or reduce our income.

Our operations expose us to fluctuations in commodity prices, and our credit facility exposes us to fluctuations in interest rates. We use over-the-counter price and basis swaps with other natural gas merchants and financial institutions. Use of these instruments is intended to reduce our exposure to short-term volatility in commodity prices. As of March 31, 2014, we have hedged only portions of our expected exposures to commodity price risk. In addition, to the extent we hedge our commodity price risk using swap instruments, we will forego the benefits of favorable changes in commodity prices. Although we do not currently have any financial instruments to eliminate our exposure to interest rate fluctuations, we may use financial instruments in the future to offset our exposure to interest rate fluctuations.

Even though monitored by management, our hedging activities may fail to protect us and could reduce our earnings and cash flow. Our hedging activity may be ineffective or adversely affect cash flow and earnings because, among other factors:

- hedging can be expensive, particularly during periods of volatile prices;
- our counterparty in the hedging transaction may default on its obligation to pay or otherwise fail to perform; and
- available hedges may not correspond directly with the risks against which we seek protection. For example:

- the duration of a hedge may not match the duration of the risk against which we seek protection;
- variations in the index we use to price a commodity hedge may not adequately correlate with variations in the index we use to sell the physical commodity (known as basis risk); and
- we may not produce or process sufficient volumes to cover swap arrangements we enter into for a given period. If our actual volumes are lower than the volumes we estimated when entering into a swap for the period, we might be forced to satisfy all or a portion of our derivative obligation without the benefit of cash flow from our sale or purchase of the underlying physical commodity, which could adversely affect our liquidity.

Our financial statements may reflect gains or losses arising from exposure to commodity prices for which we are unable to enter into fully effective hedges. In addition, the standards for cash flow hedge accounting are rigorous. Even when we engage in hedging transactions that are effective economically, these transactions may not be considered effective cash flow hedges for accounting purposes. Our earnings could be subject to increased volatility to the extent our derivatives do not continue to qualify as cash flow hedges and, if we assume derivatives as part of an acquisition, to the extent we cannot obtain or choose not to seek cash flow hedge accounting for the derivatives we assume.

Our success depends on key members of our management, the loss or replacement of whom could disrupt our business operations.

We depend on the continued employment and performance of the officers of our general partner and key operational personnel. Our general partner has entered into employment agreements with each of its executive officers. If any of these officers or other key personnel resign or become unable to continue in their present roles and are not adequately replaced, our business operations could be materially adversely affected. We do not maintain any “key man” life insurance for any officers.

Risk Inherent in an Investment in the Partnership

Cash distributions are not guaranteed and may fluctuate with our performance and the establishment of financial reserves.

Because distributions on our units are dependent on the amount of cash we generate, distributions may fluctuate based on our performance. The actual amount of cash that is available to be distributed each quarter will depend on numerous factors, some of which are beyond our control and the control of our general partner. Cash distributions are dependent primarily on cash flow, including cash flow from financial reserves and working capital borrowings and not solely on profitability, which is affected by non-cash items. Therefore, cash distributions might be made during periods when we record losses and might not be made during periods when we record profits.

We may not have sufficient available cash from operating surplus each quarter to enable us to make cash distributions at our current distribution rate under our cash distribution policy. The amount of cash we can distribute on our units principally depends upon the amount of cash we generate from our operations, which will fluctuate from quarter to quarter based on, among other things:

- the fees we charge and the margins we realize for our services;
- the prices of, levels of production of and demand for oil, natural gas, condensate and NGLs;
- the volume of natural gas we gather, compress, process, transport and sell, the volume of NGLs we process or fractionate and sell, the volume of crude oil we handle at our crude terminals, the volume of crude oil we gather, transport, purchase and sell and the volumes of brine we dispose;
- the relationship between natural gas and NGL prices;
- cash settlements of hedging positions;
- the level of competition from other midstream energy companies;
- the level of our operating and maintenance and general and administrative costs; and

- prevailing economic conditions.

In addition, the actual amount of cash we will have available for distribution will depend on other factors, some of which are beyond our control, including:

- the level of capital expenditures we make;
- our ability to make borrowings under our credit facility to pay distributions;
- the cost of acquisitions;
- our debt service requirements and other liabilities;
- fluctuations in our working capital needs;
- general and administrative expenses;
- restrictions on distributions contained in our debt agreements; and
- the amount of cash reserves established by our general partner for the proper conduct of our business.

Devon, through its control of ENLC controls our general partner, which has sole responsibility for conducting our business and managing our operations. Devon, ENLC and our general partner have conflicts of interest with, and may favor Devon's interests to the detriment of, our unitholders.

Devon, through its control of ENLC, controls our general partner and indirectly has the power to appoint all of the officers and directors of our general partner. Although our general partner has a fiduciary duty to manage us in a manner that is beneficial to us and our unitholders, the directors and officers of our general partner have a fiduciary duty to manage our general partner in a manner that is beneficial to its owner, ENLC in which Devon owns the manager and a 70.4% limited liability company interest as of March 31, 2014. Conflicts of interest may arise in the future among Devon, ENLC and its affiliates, including our general partner, on the one hand, and our partnership and our unitholders, on the other hand. As a result of these conflicts our general partner may favor its own interests and those of its affiliates, including Devon and ENLC, over our interests. These conflicts include, among others, the following situations:

Conflicts Relating to Control

- our partnership agreement limits our general partner's liability and reduces its fiduciary duties, while also restricting the remedies available to our unitholders for actions that might, without these limitations, constitute breaches of fiduciary duty by our general partner;
- in resolving conflicts of interest, our general partner is allowed to take into account the interests of parties in addition to unitholders, which has the effect of limiting its fiduciary duties to the unitholders;
- our general partner's affiliates may engage in limited competition with us;
- our general partner controls the enforcement of obligations owed to us by our general partner and its affiliates;
- our general partner decides whether to retain separate counsel, accountants or others to perform services for us;
- in some instances our general partner may cause us to borrow funds from affiliates of the general partner or from third parties in order to permit the payment of cash distributions, even if the purpose or effect of the borrowing is to make incentive distributions; and
- our partnership agreement gives our general partner broad discretion in establishing financial reserves for the proper conduct of our business. These reserves also will affect the amount of cash available for distributions.

Conflicts Relating to Costs

- our general partner determines the amount and timing of asset purchases and sales, capital expenditures, borrowings, issuance of additional limited partner interests and reserves;
- our general partner determines which costs incurred by it and its affiliates are reimbursable by us; and
- our general partner is not restricted from causing us to pay it or its affiliates for any services rendered on terms that are fair and reasonable to us or entering into additional contractual arrangements with any of these entities on our behalf.

Our unitholders have no right to elect our general partner or the directors of our general partner and have limited ability to remove our general partner.

Unlike the holders of common stock in a corporation, unitholders have only limited voting rights on matters affecting our business, and therefore limited ability to influence management's decisions regarding our business. Unitholders did not elect our general partner or the board of directors of our general partner and have no right to elect our general partner or the board of directors of our general partner on an annual or other continuing basis.

Furthermore, if unitholders are dissatisfied with the performance of our general partner, they will have little ability to remove our general partner. The general partner generally may not be removed except upon the vote of the holders of 66 2/3% of the outstanding units voting together as a single class. Affiliates of the general partner controlled approximately 59.7% of all the outstanding units as of March 31, 2014.

In addition, unitholders' voting rights are further restricted by the partnership agreement. It provides that any units held by a person that owns 20.0% or more of any class of units then outstanding, other than our general partner, its affiliates, their transferees and persons who acquired such units with the prior approval of the board of directors of the general partner, cannot be voted on any matter. In addition, the partnership agreement contains provisions limiting the ability of unitholders to call meetings or to acquire information about our operations, as well as other provisions limiting the unitholders' ability to influence the manner or direction of management.

As a result of these provisions, it will be more difficult for a third party to acquire our partnership without first negotiating such a purchase with our general partner and, as a result, our unitholders are less likely to receive a takeover premium.

Cost reimbursements due to our general partner may be substantial and will reduce the cash available for distribution to our unitholders.

Prior to making any distributions on the units, we reimburse our general partner and its affiliates, including officers and directors of our general partner, for all expenses they incur on our behalf. The reimbursement of expenses could adversely affect our ability to make distributions to our unitholders. Our general partner has sole discretion to determine the amount of these expenses.

The control of our general partner may be transferred to a third party without unitholder consent.

The general partner may transfer its general partner interest in us to a third party in a merger or in a sale of all or substantially all of its assets without the consent of the unitholders. Furthermore, there is no restriction in the partnership agreement on the ability of (i) ENLC to transfer all or a portion of its ownership interest in the general partner to a third party or (ii) Devon to transfer all or a portion of its ownership interest in ENLC and/or ENLC's manager to a third party. The new owner of the general partner or ENLC's manager, as the case may be, would then be in a position to replace the board of directors and officers of the general partner with its own choices and to control the decisions taken by the board of directors and officers.

Our general partner's absolute discretion in determining the level of cash reserves may adversely affect our ability to make cash distributions to our unitholders.

Our partnership agreement requires our general partner to deduct from operating surplus cash reserves that in its reasonable discretion are necessary to fund our future operating expenditures. In addition, the partnership agreement permits our general partner to reduce available cash by establishing cash reserves for the proper conduct of our business, to comply with applicable law or agreements to which we are a party or to provide funds for future distributions to partners. These cash reserves will affect the amount of cash available for distribution to our unitholders.

Our partnership agreement contains provisions that reduce the remedies available to our unitholders for actions that might otherwise constitute a breach of fiduciary duty by our general partner.

Our partnership agreement limits the liability and reduces the fiduciary duties of our general partner to our unitholders. The partnership agreement also restricts the remedies available to our unitholders for actions that would otherwise constitute breaches of our general partner's fiduciary duties. If you own a unit, you will be treated as having consented to the various actions contemplated in the partnership agreement and conflicts of interest that might otherwise be considered a breach of fiduciary duties under applicable state law.

We may issue additional units without our unitholders' approval, which would dilute our unitholders' ownership interests.

We may issue an unlimited number of limited partner interests of any type without the approval of our unitholders. The issuance of additional limited partner interests will have the following effects:

- our existing unitholders' proportionate ownership interest in us will decrease;
- the amount of cash available for distribution on each unit may decrease;
- the relative voting strength of each previously outstanding unit may be diminished; and
- the market price of the common units may decline.

Our general partner has a limited call right that may require our unitholders to sell their common units at an undesirable time or price.

If at any time our general partner and its affiliates own more than 80.0% of the common units, our general partner will have the right, but not the obligation, which it may assign to any of its affiliates or to us, to acquire all, but not less than all, of the common units held by unaffiliated persons at a price not less than their then-current market price. As a result, our unitholders may be required to sell their common units at an undesirable time or price and may therefore not receive any return on their investment. Existing unitholders may also incur a tax liability upon a sale of their units. As of March 31, 2014, ENLC and its affiliates owned 59.7% of our outstanding common units.

ENLC or its affiliates, including our largest holder Devon, may sell units in the public or private markets, and such sales could have an adverse impact on the trading price of the common units.

As of March 31, 2014, ENLC and its affiliates, including our largest holder Devon, held an aggregate of 138,552,244 units. The sale of any or all of these units in the public or private markets could have an adverse impact on the price of common units or on any trading market on which common units are held.

Our unitholders may not have limited liability if a court finds that unitholder action constitutes control of our business.

Our unitholders could be held liable for our obligations to the same extent as a general partner if a court determined that the right or the exercise of the right by our unitholders to remove or replace our general partner, to approve amendments to our partnership agreement, or to take other action under our partnership agreement constituted participation in the "control" of our business, to the extent that a person who has transacted business with the Partnership reasonably believes, based on our unitholders' conduct, that our unitholders are a general partner. Our general partner generally has unlimited liability for the obligations of the Partnership, such as its debts and environmental liabilities, except for those contractual obligations of the Partnership that are expressly made without recourse to our general partner. In addition, Section 17-607 of the Delaware Revised Uniform Limited Partnership Act provides that a limited partner who receives a distribution and knew at the time of the distribution that the distribution was in violation of that section may be liable to the limited partnership for the amount of the distribution for a period of three years from the date of the distribution. The limitations on the liability of holders of limited partner interests for the obligations of a limited partnership have not been clearly established in some of the other states in which we do business.

Tax Risks to Our Unitholders

Our tax treatment depends on our status as a partnership for federal income tax purposes, as well as our not being subject to entity level taxation by individual states. If the IRS treats us as a corporation or we become subject to entity level taxation for state tax purposes, it would substantially reduce the amount of cash available for distribution to you.

The anticipated after-tax economic benefit of an investment in us depends largely on our being treated as a partnership for federal income tax purposes.

If we were treated as a corporation for federal income tax purposes, we would pay additional tax on our income at corporate rates of up to 35.0% (under the law as of the date of this report) and we would probably pay state income taxes as well. In addition, distributions to unitholders would generally be taxed again as corporate distributions and none of our income, gains, losses or deductions would flow through to unitholders. Because a tax would be imposed upon us as a corporation, the cash available for distribution to unitholders would be substantially reduced. Therefore, treatment of us as a corporation would result in a material reduction in the anticipated cash flow and after-tax return to the unitholders and thus would likely result in a material reduction in the value of the common units.

Current law may change so as to cause us to be treated as a corporation for federal income tax purposes or otherwise subject us to entity-level taxation. At the federal level, members of Congress have considered substantive changes to the existing U.S. tax laws that would have affected certain publicly traded partnerships. Although the legislation considered would not have appeared to affect our tax treatment, we are unable to predict whether any such change or other proposals will ultimately be enacted. Moreover, any modification to the federal income tax laws and interpretations thereof may or may not be applied retroactively. At the state level, because of widespread state budget deficits, several states are evaluating ways to subject partnerships to entity level taxation through the imposition of state income, franchise and other forms of taxation. For example, we are required to pay Texas franchise tax at a maximum effective rate of 1.0% of our gross income apportioned to Texas in the prior year. If federal income tax or material amounts of additional state tax were to be imposed on us, the cash available for distribution to unitholders could be reduced and/or the value of an investment in our common units would be adversely impacted. Our partnership agreement provides that, if a law is enacted or existing law is modified or interpreted in a manner that subjects us to taxation as a corporation or otherwise subjects us to entity-level taxation for federal, state, or local income tax purposes, the minimum quarterly distribution amount and the target distribution amounts will be decreased to reflect the impact of that law on us.

If the IRS contests the federal income tax positions we take, the market for our common units may be adversely impacted and the costs of any contest could reduce the cash available for distribution to our unitholders.

We have not requested any ruling from the IRS with respect to our treatment as a partnership for federal income tax purposes or any other matter affecting us. The IRS may adopt positions that differ from our counsel's conclusions expressed in this annual report or from the positions we take. It may be necessary to resort to administrative or court proceedings to sustain some or all of our counsel's conclusions or the positions we take. A court may not agree with all of our counsel's conclusions or the positions we take. Any contest with the IRS may materially and adversely impact the market for our common units and the prices at which our common units trade. In addition, our costs of any contest with the IRS will be borne by us and therefore indirectly by our unitholders and our general partner since such costs will reduce the amount of cash available for distribution by us.

Unitholders may be required to pay taxes on their share of our taxable income even if they do not receive any cash distributions from us.

Because our unitholders will be treated as partners to whom we will allocate taxable income which could be different in amount than the cash we distribute, they will be required to pay federal income taxes and, in some cases, state and local income taxes on their share of our taxable income even if they do not receive cash distributions from us. Unitholders may not receive cash distributions from us equal to their share of our taxable income or even the tax liability that results from that income.

Tax gain or loss on the disposition of our common units could be different than expected.

Unitholders who sell common units will recognize gain or loss equal to the difference between the amount realized and their tax basis in those common units. Because distributions in excess of the unitholders' allocable share of total net taxable income decrease the unitholder's tax basis in his or her units, the amount, if any, of such prior excess distributions with respect to the units sold by the unitholder, will, in effect, become taxable income to the unitholder if the common unit is sold at a price greater than the tax basis in that common unit, even if the price received is less than the original cost. Furthermore, a substantial portion of the amount realized, whether or not representing gain, may be taxed as ordinary income to the unitholder due to potential recapture items, including depreciation recapture. In addition, because the amount realized includes a unitholder's share of our non-recourse liabilities, a unitholder who sells units may incur a tax liability in excess of the amount of cash received from the sale.

Tax-exempt entities and foreign persons face unique tax issues from owning common units that may result in adverse tax consequences to them.

Investment in common units by tax-exempt entities, such as individual retirement accounts (known as IRAs), pension plans, and non-U.S. persons, raises issues unique to them. For example, virtually all of our income allocated to organizations exempt from federal income tax, including individual retirement accounts and other qualified retirement plans, will be unrelated business income and will be taxable to them. Distributions to non-U.S. persons will be reduced by withholding taxes, at the highest applicable effective tax rate, and non-U.S. persons will be required to file federal income tax returns and generally pay tax on their share of our taxable income. If you are a tax-exempt entity or a foreign person, you should consult your tax advisor before investing in our common units.

We will treat each purchase of common units as having the same tax benefits without regard to the specific units purchased. The IRS may challenge this treatment, which could adversely affect the value of the common units.

Because we cannot match transferors and transferees of common units and because of other reasons, we will take depreciation and amortization positions that may not conform to all aspects of existing Treasury regulations. A successful IRS challenge to those positions could adversely affect the amount of tax benefits available to unitholders. It also could affect the timing of these tax benefits or the amount of gain from the sale of common units and could have a negative impact on the value of our common units or result in audit adjustments to the tax returns of unitholders.

The sale or exchange of 50% or more of our capital and profits interests within a 12-month period will result in the termination of our partnership for federal income tax purposes.

We will be considered to have terminated our partnership for federal income tax purposes if there is a sale or exchange of 50% or more of the total interests in our capital and profits within a 12-month period. Our termination would, among other things, result in the closing of our taxable year for all unitholders, which would result in us filing two tax returns (and our unitholders could receive two Schedules K-1 if relief was not available, as described below) for one fiscal year if the termination occurs on a day other than December 31. Our termination could also result in a deferral of depreciation deductions allowable in computing our taxable income. In the case of a unitholder who has adopted a taxable year other than a fiscal year ending December 31, the closing of our taxable year may also result in more than twelve months of our taxable income or loss being includable in such unitholder's taxable income for the year of termination. Our termination would cause us to be treated as a new partnership for tax purposes for which we must make new tax elections, and we could be subject to penalties if we were to fail to recognize and properly report on our tax return that a termination occurred.

The IRS has recently announced a publicly traded partnership technical termination relief program whereby, if a publicly traded partnership that technically terminated its partnership makes a request for publicly traded partnership technical termination relief and such relief is granted by the IRS then, among other things, the partnership will only have to provide one Schedule K-1 to unitholders for the year notwithstanding two partnership tax years.

The tax treatment of publicly traded partnerships or an investment in our common units could be subject to potential legislative, judicial or administrative changes and differing interpretations, possibly on a retroactive basis.

The present federal income tax treatment of publicly traded partnerships, including us, or an investment in our common units, may be modified by administrative, legislative or judicial interpretation at any time. Any modification to the federal income tax laws and interpretations thereof may or may not be applied retroactively. Moreover, any such modification could make it more difficult or impossible for us to meet the exception which allows publicly traded partnerships that generate qualifying income to be treated as partnerships (rather than corporations) for U.S. federal income tax purposes, affect or cause us to change our business activities, or affect the tax consequences of an investment in our common units. For example, members of Congress have been considering substantive changes to the definition of qualifying income and the treatment of certain types of income earned from profits interests in partnerships. While these specific proposals would not appear to affect our treatment as a partnership, we are unable to predict whether any of these changes, or other proposals, will ultimately be enacted. Any such changes could negatively impact the value of an investment in our common units.

We will adopt certain valuation methodologies and monthly conventions for federal income tax purposes that may result in a shift of income, gain, loss and deduction between our general partner and our unitholders. The IRS may challenge this treatment, which could adversely affect the value of the common units.

When we issue additional units or engage in certain other transactions, we will determine the fair market value of our assets and allocate any unrealized gain or loss attributable to our assets to the capital accounts of our unitholders and our general partner. Our methodology may be viewed as understating the value of our assets. In that case, there may be a shift of income, gain, loss and deduction between certain unitholders and our general partner, which may be unfavorable to such unitholders. Moreover, under our valuation methods, subsequent purchasers of common units may have a greater portion of their Internal Revenue Code Section 743(b) adjustment allocated to our tangible assets and a lesser portion allocated to our intangible assets. The IRS may challenge our valuation methods, or our allocation of the Section 743(b) adjustment attributable to our tangible and intangible assets, and allocations of taxable income, gain, loss and deduction between our general partner and certain of our unitholders.

A successful IRS challenge to these methods or allocations could adversely affect the amount of taxable income or loss being allocated to our unitholders. It also could affect the amount of taxable gain from our unitholders' sale of common units and could have a negative impact on the value of the common units or result in audit adjustments to our unitholders' tax returns without the benefit of additional deductions.

Tax Treatment of Income Earned Through C Corporation Subsidiaries

A material portion of our taxable income is earned through C corporation subsidiaries. Such C corporation subsidiaries are subject to federal income tax on their taxable income at the corporate tax rate, which is currently a maximum of 35%, and will likely pay state (and possibly local) income tax at varying rates, on their taxable income. Any such entity level taxes will reduce the cash available for distribution to our unitholders. Distributions from any such C corporation subsidiary will generally be taxed again to unitholders as dividend income to the extent of current and accumulated earnings and profits of such subsidiary. As of January 1, 2014, the maximum federal income tax rate applicable to such dividend income which is allocable to individuals is 20%. An individual unitholder's share of dividend and interest income from our C corporation subsidiaries would constitute portfolio income that could not be offset by the unitholder's share of our other losses or deductions.

As a result of investing in our common units, you will likely be subject to state and local taxes and return filing or withholding requirements in jurisdictions where you do not live.

In addition to federal income taxes, you will likely be subject to other taxes such as state and local income taxes, unincorporated business taxes and estate, inheritance or intangible taxes that are imposed by the various jurisdictions in which we do business or own property. You will likely be required to file state and local tax returns and pay state and local income taxes in some or all of the various jurisdictions in which we do business or own property and you may be subject to penalties for failure to comply with those requirements. We own property or conduct business in a number of states, most of which currently impose a state income tax on individuals. Most of these states also impose an income tax on corporations and other entities. As we make acquisitions or expand our business, we may do business or own property in other states that impose an income tax. It is our unitholders' responsibility to file all federal, state, local, and foreign tax returns. Under the tax laws of some states where we will conduct business, we may be required to withhold a percentage from amounts to be distributed to a unitholder who is not a resident of that state. Our counsel has not rendered an opinion on the state, local, or foreign tax consequences of owning our common units.

We prorate our items of income, gain, loss and deduction between transferors and transferees of our units each month based upon the ownership of our units on the first day of each month, instead of on the basis of the date a particular unit is transferred. The IRS may challenge this treatment, which could change the allocation of items of income, gain, loss and deduction among our unitholders.

We prorate our items of income, gain, loss and deduction between transferors and transferees of our units each month based upon the ownership of our units on the first day of each month, instead of on the basis of the date a particular unit is transferred. The use of this proration method may not be permitted under existing Treasury Regulations, and, accordingly, our counsel is unable to opine as to the validity of this method. Recently, the U.S. Treasury Department issued proposed Treasury Regulations that provide a safe harbor pursuant to which publicly traded partnerships may use a similar monthly simplifying convention to allocate tax items among transferor and transferee unitholders. Nonetheless, the proposed regulations do not specifically authorize the use of the proration method we have adopted. If the IRS were to challenge this method or new

Treasury regulations were issued, we may be required to change the allocation of items of income, gain, loss and deduction among our unitholders.

A unitholder whose units are loaned to a "short seller" to cover a short sale of units may be considered as having disposed of those units. If so, he would no longer be treated for tax purposes as a partner with respect to those units during the period of the loan and may recognize gain or loss from the disposition.

Because a unitholder whose units are loaned to a "short seller" to cover a short sale of units may be considered as having disposed of the loaned units, he may no longer be treated for tax purposes as a partner with respect to those units during the period of the loan to the short seller and the unitholder may recognize gain or loss from such disposition. Moreover, during the period of the loan to the short seller, any of our income, gain, loss or deduction with respect to those units may not be reportable by the unitholder and any cash distributions received by the unitholder as to those units could be fully taxable as ordinary income. Our counsel has not rendered an opinion regarding the treatment of a unitholder where common units are loaned to a short seller to cover a short sale of common units; therefore, unitholders desiring to assure their status as partners and avoid the risk of gain recognition from a loan to a short seller are urged to modify any applicable brokerage account agreements to prohibit their brokers from borrowing their units.

Compliance with and changes in tax law could adversely affect our performance.

We are subject to extensive tax laws and regulations, including federal and state income taxes and transactional taxes such as excise, sales/use, payroll, franchise and ad valorem taxes. New tax laws and regulations and changes in existing tax laws and regulations are continuously being enacted that could result in increased tax expenditures in the future. Many of these tax liabilities are subject to audits by the respective taxing authority. These audits may result in additional taxes as well as interest and penalties.

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).
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	—	Sixth Amended and Restated Agreement of Limited Partnership of Crosstex Energy, L.P., dated as of March 23, 2007 (incorporated by reference to Exhibit 3.1 to our Current Report on Form 8-K dated March 23, 2007, filed with the Commission on March 27, 2007).
3.5	—	Amendment No. 1 to Sixth Amended and Restated Agreement of Limited Partnership of Crosstex Energy, L.P. dated December 20, 2007 (incorporated by reference to Exhibit 3.1 to our Current Report on Form 8-K dated December 20, 2007, filed with the Commission on December 21, 2007).
3.6	—	Amendment No. 2 to Sixth Amended and Restated Agreement of Limited Partnership of Crosstex Energy, L.P. (incorporated by reference to Exhibit 3.1 to our Current Report on Form 8-K dated March 27, 2008, filed with the Commission on March 28, 2008).
3.7	—	Amendment No. 3 to Sixth Amended and Restated Agreement of Limited Partnership of Crosstex Energy, L.P., dated as of January 19, 2010 (incorporated by reference to Exhibit 3.1 to our Current Report on Form 8-K dated January 19, 2010, filed with the Commission on January 22, 2010).
3.8	—	Amendment No. 4 to Sixth Amended and Restated Agreement of Limited Partnership of Crosstex Energy, L.P., dated as of September 13, 2012 (incorporated by reference to Exhibit 3.1 to our Current Report on Form 8-K dated September 13, 2012, filed with the Commission on September 14, 2012).
3.9	—	Amendment No. 5 to Sixth Amended and Restated Agreement of Limited Partnership of Crosstex Energy, L.P., dated as of March 7, 2014 (incorporated by reference to Exhibit 3.8 to our Annual Report on Form 10-K for the year ended December 31, 2013, filed with the Commission on February 28, 2014).
3.10	—	Amendment No. 6 to Sixth Amended and Restated Agreement of Limited Partnership of Crosstex Energy, L.P., dated as of March 7, 2014 (incorporated by reference to Exhibit 3.4 to our Current Report on Form 8-K dated March 6, 2014, filed with the Commission on March 11, 2014).
3.11	—	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).
3.12	—	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).
3.13	—	Second Amended and Restated Limited Liability Company Agreement of EnLink Midstream GP, LLC, dated as of March 7, 2014 (incorporated by reference to Exhibit 3.2 to our Current Report on Form 8-K dated March 6, 2014, filed with the Commission on March 11, 2014).
4.1	—	Unitholder Agreement, dated as of March 7, 2014, by and among Devon Energy Corporation, Devon Gas Corporation, Devon Gas Services, L.P., Southwestern Gas Pipeline, Inc. and EnLink Midstream Partners, LP (incorporated by reference to Exhibit 4.1 to our Current Report on Form 8-K dated March 6, 2014, filed with the Commission on March 11, 2014).
4.2	—	Fifth Supplemental Indenture, dated as of March 19, 2014, by and among EnLink Midstream Partners, LP, EnLink Midstream Finance Corporation and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.1 to our Current Report on Form 8-K dated March 19, 2014, filed with the Commission on March 21, 2014).

4.3	—	Indenture, dated as of March 19, 2014, by and between EnLink Midstream Partners, LP and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.2 to our Current Report on Form 8-K dated March 19, 2014, filed with the Commission on March 21, 2014).
4.4	—	First Supplemental Indenture, dated as of March 19, 2014, by and between EnLink Midstream Partners, LP and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.3 to our Current Report on Form 8-K dated March 19, 2014, filed with the Commission on March 21, 2014).
10.1	—	Preferential Rights Agreement, dated as of March 7, 2014, by and among EnLink Midstream, Inc., EnLink Midstream Partners, LP and EnLink Midstream, LLC (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K dated March 6, 2014, filed with the Commission on March 11, 2014).
10.2†	—	Gas Gathering and Processing Contract-Bridgeport Plant, dated as of March 7, 2014, by and between Devon Gas Services, L.P. and EnLink Midstream Services, LLC (incorporated by reference to Exhibit 10.2 to our Current Report on Form 8-K dated March 6, 2014, filed with the Commission on March 11, 2014).
10.3†	—	Gas Gathering and Processing Contract-Cana Plant, dated as of March 7, 2014, by and between Devon Gas Services, L.P. and EnLink Midstream Services, LLC (incorporated by reference to Exhibit 10.3 to our Current Report on Form 8-K dated March 6, 2014, filed with the Commission on March 11, 2014).
10.4†	—	Gas Gathering and Processing Contract-Northridge Plant, dated as of March 7, 2014, by and between Devon Gas Services, L.P. and EnLink Midstream Services, LLC (incorporated by reference to Exhibit 10.4 to our Current Report on Form 8-K dated March 6, 2014, filed with the Commission on March 11, 2014).
10.5†	—	Gas Gathering and Processing Contract-East Johnson County System, dated as of March 7, 2014, by and between Devon Gas Services, L.P. and SWG Pipeline, L.L.C. (incorporated by reference to Exhibit 10.5 to our Current Report on Form 8-K dated March 6, 2014, filed with the Commission on March 11, 2014).
10.6	—	Form of Indemnification Agreement (incorporated by reference to Exhibit 10.6 to our Current Report on Form 8-K dated March 6, 2014, filed with the Commission on March 11, 2014).
10.7	—	Consulting Services Agreement, dated as of March 7, 2014, by and between William W. Davis and EnLink Midstream Operating, LP (incorporated by reference to Exhibit 10.7 to our Current Report on Form 8-K dated March 6, 2014, filed with the Commission on March 11, 2014).
10.8	—	EnLink Midstream GP, LLC Long-Term Incentive Plan, as amended and restated on March 7, 2014 (incorporated by reference to Exhibit 10.8 to our Current Report on Form 8-K dated March 6, 2014, filed with the Commission on March 11, 2014).
10.9	—	Form of First Amendment to Employment Agreement Amendment (incorporated by reference to Exhibit 10.25 to our Annual Report on Form 10-K for the year ended December 31, 2013, filed with the Commission on February 28, 2014).
10.10	—	Ninth Amendment to Amended and Restated Credit Agreement, dated as of January 22, 2014, by and among EnLink Midstream Partners, LP, Bank of America, N.A., as Administrative Agent and L/C Issuer, and the other lenders party thereto (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K dated January 22, 2014, filed with the Commission on January 22, 2014).
10.11	—	Credit Agreement, dated as of February 20, 2014, by and among EnLink Midstream Partners, LP, Bank of America, N.A., as Administrative Agent, Swing Line Lender and L/C Issuer thereunder, Citibank, N.A. and Wells Fargo Bank, National Association, as Co-Syndication Agents, Royal Bank of Canada and Bank of Montreal, as Co-Documentation Agents, and the other lenders party thereto (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K dated February 20, 2014, filed with the Commission on February 21, 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 March 31, 2014, formatted in XBRL (eXtensible Business Reporting Language): (i) Condensed Consolidated Balance Sheets as of March 31, 2014 and December 31, 2013, (ii) Condensed Consolidated Statements of Operations for the three months ended March 31, 2014 and 2013, (iii) Consolidated Statements of Changes in Partners' Equity for the three months ended March 31, 2014, (iv) Consolidated Statements of Cash Flows for the three months ended March 31, 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.

† Portions of this exhibit have been omitted pursuant to a request for confidential treatment filed with the Securities and Exchange Commission under Rule 24b-2. The omitted confidential material has been filed separately with the Securities and Exchange Commission. The location of the omitted confidential information is indicated in the exhibit with asterisks (***).

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

May 9, 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: May 9, 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: May 9, 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 March 31, 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

May 9, 2014

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

May 9, 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.