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

FORM 10-Q

☒ **QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the quarterly period ended September 30, 2014

OR

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from to

Commission file number 1-36175

MIDCOAST ENERGY PARTNERS, L.P.
(Exact Name of Registrant as Specified in Its Charter)

Delaware	**61-1714064**
(State or Other Jurisdiction of Incorporation or Organization)	**(I.R.S. Employer Identification No.)**

1100 Louisiana
Suite 3300
Houston, Texas 77002
(Address of Principal Executive Offices) (Zip Code)

(713) 821-2000
(Registrant's Telephone Number, Including Area Code)

Indicate by check mark whether the 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 Exchange Act). Yes ☐ No ☒

The registrant had 22,610,056 Class A common units outstanding as of November 3, 2014.

MIDCOAST ENERGY PARTNERS, L.P.

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In this report, unless the context otherwise requires, references to "the Predecessor," "we," "our," "us," or like terms, when used in a historical context (before November 13, 2013), refer to Midcoast Operating, L.P. and its subsidiaries. References in this report to "Midcoast Energy Partners," "the Partnership," "MEP," "we," "our," "us," or like terms used in the present tense or prospectively (on and after November 13, 2013) refer to Midcoast Energy Partners, L.P. and its subsidiaries. We refer to our general partner, Midcoast Holdings, L.L.C., as our "General Partner" and refer to Enbridge Energy Partners, L.P. and its subsidiaries, other than us, as "Enbridge Energy Partners," or "EEP." References to "Enbridge" refer collectively to Enbridge, Inc. and its subsidiaries other than us, our subsidiaries, our General Partner, EEP, its subsidiaries and its general partner. References to "Enbridge Management" refer to Enbridge Energy Management, L.L.C., the delegate of EEP's general partner that manages EEP's business and affairs. References to "Midcoast Operating" refer to Midcoast Operating, L.P. and its subsidiaries. As of September 30, 2014, we owned a 51.6% controlling interest in Midcoast Operating, and EEP owned a 48.4% noncontrolling interest in Midcoast Operating. Unless otherwise specifically noted, financial results and operating data are shown on a 100% basis and are not adjusted to reflect EEP's 48.4% noncontrolling interest in Midcoast Operating as of September 30, 2014.

This Quarterly Report on Form 10-Q includes forward-looking statements, which are statements that frequently use words such as "anticipate," "believe," "continue," "could," "estimate," "expect," "forecast," "intend," "may," "plan," "position," "projection," "should," "strategy," "target," "will" and similar words. Although we believe that such forward-looking statements are reasonable based on currently available information, such statements involve risks, uncertainties and assumptions and are not guarantees of performance. Future actions, conditions or events and future results of operations may differ materially from those expressed in these forward-looking statements. Any forward-looking statement made by us in this Quarterly Report on Form 10-Q speaks only as of the date on which it is made, and we undertake no obligation to publicly update any forward-looking statement. Many of the factors that will determine these results are beyond our ability to control or predict. Specific factors that could cause actual results to differ from those in the forward-looking statements include: (1) changes in the demand for, the supply of, forecast data for, and price trends related to natural gas, natural gas liquids, or NGLs, and crude oil; (2) our ability to successfully complete and finance expansion projects; (3) the effects of competition, in particular, by other pipeline and gathering systems, as well as other processing and treating plants; (4) shut-downs or cutbacks at our facilities or refineries, petrochemical plants, utilities or other businesses for which we transport products or to whom we sell products; (5) hazards and operating risks that may not be covered fully by insurance; (6) changes in or challenges to our rates; and (7) changes in laws or regulations to which we are subject, including compliance with environmental and operational safety regulations that may increase costs of system integrity testing and maintenance.

For additional factors that may affect results, see "Item 1A. Risk Factors" included in our Annual Report on Form 10-K for the fiscal year ended December 31, 2013, which is available to the public over the Internet at the United States Securities and Exchange Commission's, or the SEC's, website (www.sec.gov) and at our website (www.midcoastpartners.com).

PART I—FINANCIAL INFORMATION

Item 1. Financial Statements

MIDCOAST ENERGY PARTNERS, L.P.
CONSOLIDATED STATEMENTS OF INCOME

	For the three month period ended September 30,		For the nine month period ended September 30,	
	2014	2013	2014	2013
	(unaudited; in millions, except per unit amounts)			
Operating revenues:				
Operating revenue (Note 11)	$1,348.8	$1,331.3	$4,268.4	$3,887.9
Operating revenue—affiliate (Notes 9 and 11)	50.6	49.6	174.7	162.4
	1,399.4	1,380.9	4,443.1	4,050.3
Operating expenses:				
Cost of natural gas and natural gas liquids (Notes 4 and 11)	1,208.5	1,221.3	3,888.4	3,457.9
Cost of natural gas and natural gas liquids—affiliate (Notes 9 and 11)	29.7	23.0	98.3	95.5
Operating and maintenance	54.3	61.4	165.5	181.7
Operating and maintenance—affiliate (Note 9)	26.3	27.3	81.0	81.4
General and administrative	2.5	—	6.0	0.1
General and administrative—affiliate (Note 9)	23.4	25.0	68.7	73.0
Depreciation and amortization	39.5	35.8	113.3	106.3
	1,384.2	1,393.8	4,421.2	3,995.9
Operating income (loss)	15.2	(12.9)	21.9	54.4
Interest expense, net (Notes 7 and 9)	3.6	—	9.7	—
Equity in earnings of joint ventures (Note 6)	6.1	—	7.1	—
Other income (loss)	(0.8)	—	(0.7)	0.2
Income (loss) before income tax expense	16.9	(12.9)	18.6	54.6
Income tax expense (Note 12)	0.9	0.6	2.7	8.9
Net income (loss)	16.0	(13.5)	15.9	45.7
Less: Net income attributable to noncontrolling interest	9.7	—	13.8	—
Net income (loss) attributable to general and limited partner ownership interest in Midcoast Energy Partners, L.P.	$ 6.3	$ (13.5)	$ 2.1	$ 45.7
Net income (loss) attributable to limited partner ownership interest	$ 6.2	$ (5.1)	$ 2.1	$ 17.6
Net income (loss) per limited partner unit (basic and diluted) (Note 2)	$ 0.14	$ (0.19)	$ 0.05	$ 0.66
Weighted average limited partner units outstanding	45.2	26.7	45.2	26.7

The accompanying notes are an integral part of these consolidated financial statements.

MIDCOAST ENERGY PARTNERS, L.P.
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	For the three month period ended September 30,		For the nine month period ended September 30,	
	2014	2013	2014	2013
	(unaudited; in millions)			
Net income (loss)	$16.0	$(13.5)	$15.9	$45.7
Other comprehensive income (loss), net of tax expense (benefit) of $0.0 million, $(0.1) million, $0.1 million and $0.0 million, respectively (Note 11)	10.2	(17.0)	8.6	(5.7)
Comprehensive income (loss)	26.2	(30.5)	24.5	40.0
Less: Comprehensive income attributable to:				
Noncontrolling interest (Note 9)	9.7	—	13.8	—
Other comprehensive income attributed to noncontrolling interest (Note 9)	6.3	—	5.3	—
Comprehensive income (loss) attributable to general and limited partner ownership interests in Midcoast Energy Partners, L.P.	$10.2	$(30.5)	$ 5.4	$40.0

The accompanying notes are an integral part of these consolidated financial statements.

MIDCOAST ENERGY PARTNERS, L.P.
CONSOLIDATED STATEMENTS OF CASH FLOWS

	For the nine month period ended September 30,	
	2014	2013
	(unaudited; in millions)	
Cash provided by operating activities:		
Net income	$ 15.9	$ 45.7
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	113.3	106.3
Derivative fair value net (gains) losses (Note 11)	(11.5)	13.9
Inventory market price adjustments (Note 4)	4.8	3.3
Distributions from investment in joint ventures	6.1	—
Equity earnings from investment in joint ventures (Note 6)	(7.1)	—
Deferred income taxes (Note 12)	1.4	7.5
Other	0.6	0.1
Changes in operating assets and liabilities, net of acquisitions:		
Receivables, trade and other	11.5	(28.8)
Due from General Partner and affiliates	641.7	10.6
Accrued receivables	28.0	463.2
Inventory (Note 4)	(129.1)	(75.1)
Current and long-term other assets (Note 11)	(11.5)	(7.0)
Due to General Partner and affiliates	(487.4)	(1.9)
Accounts payable and other (Notes 3 and 11)	(50.6)	(23.2)
Environmental liabilities (Note 10)	0.2	—
Accrued purchases	(21.3)	(97.5)
Interest payable	0.4	—
Property and other taxes payable	6.6	8.8
Net cash provided by operating activities	112.0	425.9
Cash used in investing activities:		
Additions to property, plant and equipment (Notes 5 and 14)	(166.6)	(206.6)
Changes in restricted cash (Note 9)	55.6	—
Asset acquisitions	—	(0.9)
Proceeds from the sale of net assets	—	5.0
Investment in joint ventures (Note 6)	(35.4)	(181.8)
Distributions from investment in joint ventures in excess of cumulative earnings	27.0	—
Other	(0.8)	(2.2)
Net cash used in investing activities	(120.2)	(386.5)
Cash provided by (used in) financing activities:		
Net proceeds from long-term debt (Note 7)	398.1	—
Net borrowings under credit facility (Note 7)	30.0	—
Distributions to Predecessor partner interests (Note 8)	—	(206.3)
Distributions to partners (Note 8)	(37.1)	—
Acquisition of noncontrolling interest in subsidiary (Note 8)	(350.0)	—
Contributions from Predecessor partner interests	—	166.9
Contributions from noncontrolling interest (Note 8)	111.8	—
Distributions to noncontrolling interest (Note 8)	(83.3)	—
Net cash provided by (used in) financing activities	69.5	(39.4)
Net increase in cash and cash equivalents	61.3	—
Cash and cash equivalents at beginning of year	4.9	—
Cash and cash equivalents at end of period	$ 66.2	$ —

The accompanying notes are an integral part of these consolidated financial statements.

MIDCOAST ENERGY PARTNERS, L.P.
CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

	September 30, 2014	December 31, 2013
	(unaudited; in millions)	
ASSETS		
Current assets:		
Cash and cash equivalents (Note 3)	$ 66.2	$ 4.9
Restricted cash (Note 9)	5.9	61.5
Receivables, trade and other, net of allowance for doubtful accounts of $0.5 million at September 30, 2014 and December 31, 2013	38.8	50.3
Due from general partner and affiliates (Note 9)	16.0	654.8
Accrued receivables	154.2	182.2
Inventory (Note 4)	212.3	88.0
Other current assets (Note 11)	42.9	19.1
	536.3	1,060.8
Property, plant and equipment, net (Note 5)	4,135.8	4,082.3
Goodwill	226.5	226.5
Intangibles, net	248.8	255.0
Equity investment in joint ventures (Note 6)	380.2	371.3
Other assets, net (Note 11)	57.6	40.5
	$5,585.2	$6,036.4
LIABILITIES AND PARTNERS' CAPITAL		
Current liabilities:		
Due to general partner and affiliates (Note 9)	$ 28.2	$ 534.3
Accounts payable and other (Notes 3, 10 and 11)	60.3	114.4
Accrued purchases	437.0	463.3
Property and other taxes payable (Note 12)	26.4	19.8
Interest payable	0.7	0.3
	552.6	1,132.1
Long-term debt (Note 7)	765.0	335.0
Other long-term liabilities (Notes 10 and 12)	30.3	16.6
Total liabilities	1,347.9	1,483.7
Commitments and contingencies (Note 10)		
Partners' capital (Note 8):		
Class A common units (22,610,056 at September 30, 2014 and December 31, 2013)	611.4	495.3
Subordinated units (22,610,056 at September 30, 2014 and December 31, 2013)	1,151.3	1,035.1
General Partner units (922,859 at September 30, 2014 and December 31, 2013)	46.9	42.2
Accumulated other comprehensive income (loss) (Note 11)	0.2	(3.1)
Total Midcoast Energy Partners, L.P. partners' capital	1,809.8	1,569.5
Noncontrolling interest	2,427.5	2,983.2
Total partners' capital	4,237.3	4,552.7
	$5,585.2	$6,036.4

The accompanying notes are an integral part of these consolidated financial statements.

MIDCOAST ENERGY PARTNERS, L.P.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (unaudited)

1. ORGANIZATION AND NATURE OF OPERATIONS

Initial Public Offering

Midcoast Energy Partners, L.P., is a publicly-traded Delaware limited partnership formed by Enbridge Energy Partners, L.P., or EEP, to serve as EEP's primary vehicle for owning and growing its natural gas and natural gas liquids midstream business in the United States. Midcoast Energy Partners, L.P., together with its consolidated subsidiaries, are referred to in this report as "we," "us," "our", "MEP" and the "Partnership". We own and operate a portfolio of assets engaged in the business of gathering, processing and treating natural gas, as well as the transportation and marketing of natural gas, natural gas liquids, or NGLs, crude oil and condensate. Our portfolio of natural gas and NGL pipelines, plants and related facilities are geographically concentrated in the Gulf Coast and Mid-Continent regions of the United States, primarily in Texas and Oklahoma. On November 13, 2013, MEP completed its initial public offering, or the Offering, of 18,500,000 Class A common units (2,775,000 additional Class A common units were issued pursuant to the exercise of the underwriters' over-allotment option on December 9, 2013), representing limited partner interests. Following the completion of the Offering, EEP continues to own crude oil and liquid petroleum assets and a non-controlling interest in Midcoast Operating. EEP also retained a significant interest in us through its ownership of our General Partner, which owns all of our General Partner units and all of our incentive distribution rights, as well as an approximate 52% limited partner interest in us. Our Class A common units began trading on November 7, 2013, on the New York Stock Exchange, or NYSE, under the ticker symbol MEP.

On July 1, 2014, we acquired an additional 12.6% limited partner interest in Midcoast Operating from EEP for $350.0 million, which brought our total ownership interest in Midcoast Operating to 51.6%. This transaction represents our first acquisition of additional interests in Midcoast Operating since the Offering.

Basis of Presentation

We have prepared the accompanying unaudited interim consolidated financial statements in accordance with accounting principles generally accepted in the United States, or GAAP, and with the instructions to Form 10-Q and Rule 10-01 of Regulation S-X. Accordingly, the unaudited interim consolidated financial statements do not include all the information and footnotes required by GAAP for complete consolidated financial statements. In the opinion of management, they contain all adjustments, consisting only of normal recurring adjustments, which management considers necessary to present fairly our financial position as of September 30, 2014, our results of operations for the three and nine month periods ended September 30, 2014, and 2013, and our cash flows for the nine month periods ended September 30, 2014, and 2013. We derived our consolidated statement of financial position as of December 31, 2013, from the audited financial statements included in our Annual Report on Form 10-K for the fiscal year ended December 31, 2013. Our results of operations for the three and nine month periods ended September 30, 2014, should not be taken as indicative of the results to be expected for the full year due to seasonal fluctuations in the supply of and demand for natural gas, NGLs and crude oil, timing and completion of our construction projects, maintenance activities, the impact of forward commodity prices and differentials on derivative financial instruments that are accounted for at fair value. These unaudited interim consolidated financial statements should be read in conjunction with the audited consolidated financial statements and accompanying footnotes thereto presented in our Annual Report on Form 10-K for the fiscal year ended December 31, 2013.

Certain adjustments relating to prior periods and having net adverse impacts of approximately $3.2 million and $3.4 million to net income for the three and nine month periods ended September 30, 2014, respectively, were recorded in the current period. We consider these adjustments to be immaterial to the unaudited interim consolidated financial statements both individually and taken as a whole.

Our results of operations may not be comparable to our Predecessor's historical results of operations for the reasons described below:

- Our Predecessor's results of operations historically reflected 100% of the revenues and expenses relating to Midcoast Operating. For the first six months of 2014, we owned a 39% controlling interest in Midcoast Operating. After July 1, 2014, we owned a 51.6% controlling interest in Midcoast Operating. We consolidate the results of operations of Midcoast Operating and then record a 48.4% non-controlling interest deduction for EEP's retained interest in Midcoast Operating. Additionally, although EEP has the option to fund its pro rata share of Midcoast Operating's capital expenditures, to the extent it elects not to do so, we may elect to fund EEP's portion in exchange for additional interests in Midcoast Operating and, as a result, our interest in Midcoast Operating would increase over time.
- Although the allocation methodology under which we will continue to reimburse EEP and its affiliates for the provisions of certain administrative and operational services to Midcoast Operating will not change, $25.0 million in annual amounts payable for general and administrative expenses that were paid by Midcoast Operating historically under its existing services agreements will not be payable by Midcoast Operating going forward.
- We expect to incur an additional $4.0 million of incremental annual general and administrative expenses as a result of being a separate publicly traded partnership, 100% of which will be attributable to us.
- EEP no longer provides letters of credit and parental guarantees to Midcoast Operating at no cost, and we are responsible for our proportionate share of the annual expenses attributable to a financial support agreement that Midcoast Operating entered into with EEP. During the term of the financial support agreement, when requested by Midcoast Operating, EEP will provide letters of credit and guarantees in support of Midcoast Operating's financial obligations under certain hedges and key customer natural gas and NGL purchase agreements. The annual cost that Midcoast Operating incurs under the financial support agreement, which we estimate will initially range from approximately $4.0 million to $5.0 million, is based on the cumulative average amount of letters of credit and guarantees that EEP may provide on Midcoast Operating's behalf multiplied by a 2.5% annual fee. Midcoast Operating incurred $2.7 million of these costs for the nine months ended September 30, 2014. Without such financial support from EEP, we expect that Midcoast Operating would be required to provide letters of credit, cash collateral or other financial support with respect to these agreements or similar agreements it enters into in the future.
- We incur interest expense under our borrowing arrangements. Before we acquired control of our Predecessor, it was a wholly owned subsidiary of EEP and, as such, did not incur any direct interest expense from third parties and only recognized intercompany interest expense to the extent such amounts were capitalized as part of its construction projects.

2. NET INCOME PER LIMITED PARTNER AND GENERAL PARTNER INTEREST

We allocate our net income among our General Partner and limited partners using the two-class method in accordance with applicable authoritative accounting guidance. Under the two-class method, we allocate our net income to our limited partners, our General Partner and the holders of our incentive distribution rights, or IDRs, in accordance with the terms of our partnership agreement. We also allocate any earnings in excess of distributions to our limited partners, our General Partner and the holders of the IDRs in accordance with the terms of our partnership agreement. We allocate any distributions in excess of earnings for the period to our General Partner and our limited partners based on their respective proportionate ownership interests in us, after taking into account distributions to be paid with respect to the IDRs, as set forth in our partnership agreement.

Distribution Targets	Portion of Quarterly Distribution Per Unit	Percentage Distributed to Limited Partners	Percentage Distributed to General Partner
Minimum Quarterly Distribution	Up to $0.3125	98 %	2 %
First Target Distribution	> $0.3125 to $0.359375	98 %	2 %
Second Target Distribution	> $0.359375 to $0.390625	85 %	15 %
Third Target Distribution	> $0.390625 to $0.468750	75 %	25 %
Over Third Target Distribution	In excess of $0.468750	50 %	50 %

We determined basic and diluted net income per limited partner unit as follows:

	For the three month period ended September 30,		For the nine month period ended September 30,	
	2014	2013 (1)	2014	2013 (1)
	(in millions, except per unit amounts)			
Net income (loss)	$ 16.0	$(13.5)	$ 15.9	$ 45.7
Less: Net income (loss) attributable to noncontrolling interest	9.7	(8.3)	13.8	27.8
Net income (loss) attributable to general and limited partner interests in Midcoast Energy Partners, L.P.	6.3	(5.2)	2.1	17.9
Less distributions:				
Total distributed earnings to our General Partner	(0.3)	(0.2)	(0.9)	(0.5)
Total distributed earnings to our limited partners	(15.3)	(8.4)	(44.1)	(25.1)
Total distributed earnings	(15.6)	(8.6)	(45.0)	(25.6)
Underdistributed (Overdistributed) earnings	$ (9.3)	$(13.8)	$(42.9)	$ (7.7)
Weighted average limited partner units outstanding	45.2	26.7	45.2	26.7
Basic and diluted earnings per unit:				
Distributed earnings per limited partner unit (2)	$ 0.34	$ 0.32	$ 0.98	$ 0.94
Underdistributed (Overdistributed) earnings per limited partner unit (3)	(0.20)	(0.51)	(0.93)	(0.28)
Net income (loss) per limited partner unit (basic and diluted)	$ 0.14	$(0.19)	$ 0.05	$ 0.66

(1) Represents calculation retrospectively reflecting the affiliate capitalization of MEP consisting of 4.1 million MEP Class A common units, 22.6 million MEP subordinated units and MEP general partner interest upon the transfer of a controlling ownership, including limited partner and general partner interest, in Midcoast Operating. The noncontrolling interest reflects the 61% retained by EEP for the three and nine month periods ended September 30, 2013.

(2) Represents the total distributed earnings to limited partners divided by the weighted average number of limited partner interests outstanding for the period.

(3) Represents the limited partners' share (98%) of distributions in excess of earnings divided by the weighted average number of limited partner interests outstanding for the period and underdistributed earnings allocated to the limited partners based on the distribution waterfall that is outlined in our partnership agreement.

3. CASH AND CASH EQUIVALENTS

We extinguish liabilities when a creditor has relieved us of our obligation, which occurs when our financial institution honors a check that the creditor has presented for payment. Accordingly, obligations for which we have made payments that have not yet been presented to the financial institution, totaling approximately \$7.9 million at September 30, 2014, and \$8.8 million at December 31, 2013, are included in "Accounts payable and other" on our consolidated statements of financial position. At December 31, 2013, we reclassified a book overdraft of \$49.1 million to "Accounts payable and other" on our consolidated statements of financial position.

4. INVENTORY

Our inventory is comprised of the following:

	September 30, 2014	December 31, 2013
	(in millions)	
Materials and supplies	\$ 0.7	\$ 0.6
Crude oil inventory	5.0	12.6
Natural gas and NGL inventory	206.6	74.8
	\$212.3	\$88.0

The "Cost of natural gas and natural gas liquids" on our consolidated statements of income includes charges totaling \$1.5 million and \$0.9 million for the three month periods ended September 30, 2014 and 2013, respectively, and \$4.8 million and \$3.3 million for the nine month periods ended September 30, 2014 and 2013, respectively, that we recorded to reduce the cost basis of our inventory of natural gas and NGLs to reflect the current market value.

5. PROPERTY, PLANT AND EQUIPMENT

Our property, plant and equipment is comprised of the following:

	September 30, 2014	December 31, 2013
	(in millions)	
Land	\$ 11.1	\$ 11.6
Rights-of-way	403.5	380.0
Pipelines	1,795.2	1,741.9
Pumping equipment, buildings and tanks	81.7	79.2
Compressors, meters and other operating equipment	2,056.3	1,993.2
Vehicles, office furniture and equipment	170.5	148.5
Processing and treating plants	514.2	514.4
Construction in progress	172.9	181.4
Total property, plant and equipment	5,205.4	5,050.2
Accumulated depreciation	(1,069.6)	(967.9)
Property, plant and equipment, net	\$ 4,135.8	\$4,082.3

6. EQUITY INVESTMENTS IN JOINT VENTURES

We have a 35% aggregate interest in the Texas Express NGL system, which is comprised of two joint ventures with third parties. The Texas NGL system consists of a 580-mile NGL intrastate transportation pipeline and a related NGL gathering system that was placed into service in the fourth quarter of 2013. Our investment in the Texas Express NGL system is presented in "Equity investment in joint ventures" on our consolidated statements of financial position. "Equity in earnings of joint ventures" on our consolidated statements of income represents our earnings related to these joint ventures. The following table presents unaudited income statement information of the Texas Express NGL system on an aggregated, 100% basis for the periods presented:

	For the three month period ended September 30,		For the nine month period ended September 30,	
	2014	2013	2014	2013
	(in millions)			
Operating revenues	$27.3	$—	$51.7	$—
Operating expenses	$ 9.7	$—	$30.0	$—
Net income	$17.5	$—	$21.6	$—

7. DEBT

The following table presents the carrying amounts, net of related unamortized discounts, of our consolidated debt obligations.

	September 30, 2014	December 31, 2013
	(in millions)	
Credit Agreement	$365.0	$335.0
3.560% Series A Senior Notes due 2019	75.0	—
4.040% Series B Senior Notes due 2021	175.0	—
4.420% Series C Senior Notes due 2024	150.0	—
Total	$765.0	$335.0

Our interest cost for the three and nine month periods ended September 30, 2014, and 2013, is comprised of the following:

	For the three month period ended September 30,		For the nine month period ended September 30,	
	2014	2013 (1)	2014	2013 (1)
	(in millions)			
Interest cost incurred	$4.0	$ 5.1	$10.3	$16.6
Interest capitalized	0.4	5.1	0.6	16.6
Interest expense, net	$3.6	$—	$ 9.7	$ —
Interest cost paid	$4.1	$ 5.1	$ 9.9	$16.6
Weighted average interest rate (2)	1.9%	—	2.0%	—

(1) Prior to the Offering, the interest cost we recognized was an allocation of EEP's cost. In connection with the closing of the Offering, the Partnership, Midcoast Operating, and their material domestic subsidiaries, entered into the Credit Agreement to establish their own committed senior revolving credit facility.

(2) At September 30, 2013, MEP had no outstanding debt and no weighted average interest rate.

Private Debt Issuance

On September 30, 2014, we completed a private debt issuance of $400.0 million. The debt consists of three tranches of senior notes: $75.0 million of 3.56% Series A Senior Notes due in 2019; $175.0 million of 4.04% Series B Senior Notes due in 2021; and $150.0 million of 4.42% Series C Senior Notes due in 2024, collectively the Notes. All of the Notes pay interest semi-annually on March 31 and September 30, commencing on March 31, 2015. We received approximately $398.1 million in net proceeds, which were used to repay outstanding indebtedness and for other general partnership purposes. Using a portion of the net proceeds, we settled two interest rate swaps for a net payment of $0.9 million on September 30, 2014, which will be amortized to interest expense over the original 5 year hedge term.

The Notes were issued pursuant to a Note Purchase Agreement, or the Purchase Agreement, between us and the purchasers named therein. The Notes and all other obligations under the Purchase Agreement are unconditionally guaranteed by each of our domestic material subsidiaries pursuant to a guaranty agreement. Until such time as we obtain an investment grade rating from either Moody's or S&P and upon certain trigger events, we and the guarantors will grant liens in our assets (subject to certain excluded assets) to secure the obligations under the Notes. There are currently no liens associated with the Notes.

Additionally, the Purchase Agreement contains various covenants and restrictive provisions which limit the ability of us and our subsidiaries to incur certain liens or permit such liens to exist, merge or consolidate with another company, dispose of assets, make distributions on or redeem or repurchase their equity interests, incur or guarantee additional debt, repay subordinated debt or certain debt owed to affiliates prior to maturity, alter our lines of business, and enter into certain types of transactions with affiliates or subsidiaries that we are permitted to designate as unrestricted subsidiaries.

The Purchase Agreement also requires compliance with two financial covenants. We must not permit the ratio of consolidated funded debt to pro forma earnings before interest, taxes, depreciation and amortization (the total leverage ratio), or EBITDA, as of the end of any applicable four quarter period, to exceed 5.00 to 1.00, or 5.50 to 1.00 during acquisition periods. We also must maintain, on a consolidated basis, as of the end of each applicable four-quarter period, a ratio of pro forma EBITDA to consolidated interest expense for such four quarter period then ended of at least 2.50 to 1.00. At September 30, 2014, we were in compliance with the terms of our financial covenants under the Purchase Agreement.

In connection with our entry into the Purchase Agreement, we, along with EEP and the guarantors, entered into a subordination agreement in which EEP agreed to subordinate its right to payment on obligations owed by Midcoast Operating under each of the Financial Support Agreement and the Working Capital Agreements, both entered into by and between EEP and Midcoast Operating on November 13, 2013, and liens, if secured, to the rights of the holders under the Purchase Agreement, subject to the terms and conditions of the subordination agreement in favor and for the benefit of the holders of the Notes.

Credit Agreement

On November 13, 2013, we, Midcoast Operating, and our material domestic subsidiaries, entered into the Credit Agreement, which permits aggregate borrowings of up to, at any one time outstanding, $850.0 million. The original term of the Credit Agreement is three years, with an initial maturity date of November 13, 2016, subject to four one-year requests for extensions. On September 30, 2014, we amended our Credit Agreement to extend the maturity date from November 13, 2016, to September 30, 2017; however, $140.0 million of commitments will expire on the original maturity date of November 13, 2016. In connection with the amendment to our Credit Agreement, we entered into an amended and restated subordination agreement by and among us, Midcoast Operating, the other parties from time to time party thereto and EEP in favor of Bank of America, N.A., as administrative agent, and for the benefit of the administrative agent and the lenders party to the Credit Agreement, to accommodate the subordination agreement entered into in connection with the Purchase Agreement, described under "Private Debt Issuance."

At September 30, 2014, we had $365.0 million in outstanding borrowings under the Credit Agreement at a weighted average interest rate of 1.9%. Under the Credit Agreement, we had net borrowings of approximately $30.0 million during the nine month period ended September 30, 2014, which includes gross borrowings of $5,570.0 million and gross repayments of $5,540.0 million. At September 30, 2014, we were in compliance with the terms of our financial covenants in the Credit Agreement.

Working Capital Credit Facility

On November 13, 2013, Midcoast Operating entered into a $250.0 million working capital credit facility with EEP as the lender. For the three and nine month periods ending September 30, 2014, approximately $0.3 million and $0.5 million, respectively, was paid by Midcoast Operating to EEP for commitment fees on the facility. At September 30, 2014, there were no outstanding borrowings under this facility.

On October 30, 2014, the board of directors of Midcoast Holdings, acting in its capacity as the General Partner of MEP, on behalf of Midcoast OLP GP, L.L.C., acting in its capacity as the general partner of Midcoast Operating, approved the termination of the working capital credit facility with EEP as the lender. Midcoast Operating has exercised its right under the working capital facility to terminate the agreement upon 30-days' notice, and such termination is expected to occur in the fourth quarter. At the time of the termination, there is not expected to be any outstanding borrowings under this facility.

Financial Support Agreement

On November 13, 2013, Midcoast Operating entered into a Financial Support Agreement with EEP, pursuant to which EEP will provide letters of credit and guarantees, not to exceed $700.0 million in the aggregate at any time outstanding, in support of Midcoast Operating's and its wholly owned subsidiaries' financial obligations under derivative agreements and natural gas and NGL purchase agreements to which Midcoast Operating, or one or more of its wholly owned subsidiaries, is a party.

The annual costs that Midcoast Operating initially estimated that it will incur under the Financial Support Agreement ranged from approximately $4.0 million to $5.0 million and are based on the cumulative average amount of letters of credit and guarantees that EEP will provide on Midcoast Operating's and its wholly owned subsidiaries' behalf multiplied by a 2.5% annual fee. Midcoast Operating incurred $0.5 million and $2.7 million of these costs for the three and nine month periods ending September 30, 2014, which is included in "Operating and maintenance" on our consolidated statements of income.

Available Credit

At September 30, 2014, we have approximately $735.0 million available under the terms of our Credit Agreement and the working capital credit facility, determined as follows:

	(in millions)
Total credit available under Credit Agreement	$ 850.0
Less: Amounts outstanding under Credit Agreement	(365.0)
Total credit available under working capital credit facility	250.0
Total amount available at September 30, 2014	$ 735.0

On a pro forma basis, as of September 30, 2014, we would have had $485.0 million available under the terms of our Credit Agreement, taking into consideration the termination of our $250.0 million working capital credit facility.

Fair Value of Debt Obligations

The carrying amounts of our outstanding borrowings under the Credit Agreement approximate the fair values at September 30, 2014, and December 31, 2013, respectively, due to the short-term nature and frequent repricing of the amounts outstanding under these obligations. The outstanding borrowings under the Credit Agreement are included with our long-term debt obligations above since we have the ability and the intent to refinance the amounts outstanding on a long-term basis.

The approximate fair values of our fixed-rate debt obligations was $376.3 million at September 30, 2014. We determined the approximate fair values using a standard methodology that incorporates pricing points that are obtained from independent, third-party investment dealers who actively make markets in our debt securities. We use these pricing points to calculate the present value of the principal obligation to be repaid at maturity and all future interest payment obligations for any debt outstanding. The fair value of our long-term debt obligations is categorized as Level 2 within the fair value hierarchy.

8. PARTNERS' CAPITAL

Distribution to Partners

The following table sets forth our distributions, as approved by the board of directors of Midcoast Holdings, L.L.C, our General Partner, during the nine month period ended September 30, 2014.

Distribution Declaration Date	Record Date	Distribution Payment Date	Distribution per Unit	Cash Distributed
			(in millions, except per unit amounts)	
July 30, 2014	August 7, 2014	August 14, 2014	$0.32500	$15.0
April 29, 2014	May 8, 2014	May 15, 2014	$0.31250	$14.4
January 29, 2014	February 7, 2014	February 14, 2014	$0.16644	$7.7

Changes in Partners' Capital

The following table presents significant changes in partners' capital accounts attributable to our General Partner and limited partners as well as the noncontrolling interest in our consolidated subsidiary during the nine month periods ended September 30, 2014 and 2013.

	For the nine month period ended September 30,	
	2014	2013
	(in millions)	
Class A common units:		
Beginning balance	$ 495.3	$ —
Net income	1.0	—
Acquisition of noncontrolling interest in subsidiary	133.3	—
Distributions	(18.2)	—
Ending balance	$ 611.4	$ —
Subordinated units:		
Beginning balance	$1,035.1	$ —
Net income	1.1	—
Acquisition of noncontrolling interest in subsidiary	133.3	—
Distributions	(18.2)	—
Ending balance	$1,151.3	$ —
General Partner units:		
Beginning balance	$ 42.2	$ —
Net income	—	—
Acquisition of noncontrolling interest in subsidiary	5.4	—
Distributions	(0.7)	—
Ending balance	$ 46.9	$ —
Limited Partner: [(1)]		
Beginning balance	$ —	$4,707.1
Capital contribution	—	166.9
Net income	—	45.7
Distributions	—	(206.3)
Ending balance	$ —	$4,713.4
Accumulated other comprehensive income (loss)		
Beginning balance	$ (3.1)	$ 7.1
Changes in fair value of derivative financial instruments reclassified to earnings	5.1	(3.0)
Changes in fair value of derivative financial instruments recognized in other comprehensive income (loss)	(1.8)	(2.7)
Ending balance	$ 0.2	$ 1.4
Noncontrolling interest		
Beginning balance	$2,983.2	$ —
Capital contributions	130.5	—
Acquisition of noncontrolling interest in subsidiary	(622.0)	—
Comprehensive income:		
Net income	13.8	—
Other comprehensive income, net of tax	5.3	—
Distributions to noncontrolling interest	(83.3)	—
Ending balance	$2,427.5	$ —
Total partners' capital at end of period	$4,237.3	$4,714.8

(1) These amounts represent the changes in the capital account for the nine month period ended September 30, 2013, of the former limited partner of Midcoast Operating, our predecessor for accounting purposes. These changes are not to the Partnership's limited partner interests, and thus, are shown here separately.

Acquisition of Additional Interests in Midcoast Operating

On July 1, 2014, we acquired a 12.6% limited partner interest in Midcoast Operating from EEP for $350.0 million, which brought our total ownership interest in Midcoast Operating to 51.6%. This transaction represents our first acquisition of additional interests in Midcoast Operating since the Offering. We do not know when, or if, any additional interests will be offered to us to purchase.

We recorded the change in our total ownership interest as an equity transaction. No gain on the acquisition was recognized in our consolidated statements of income or comprehensive income. We reduced the book value of the related "Noncontrolling interest" in Midcoast Operating by $622.0 million in our consolidated statement of financial position as of September 30, 2014. The $272.0 million difference between the acquisition price and the book value of the noncontrolling interest was recorded as an increase to the partners' capital accounts on a pro-rata basis. In addition, accumulated other comprehensive income, or AOCI, of $0.9 million representing the noncontrolling interest of AOCI for Midcoast Operating was reclassified to AOCI attributable to us.

Securities Authorized for Issuance under Equity Compensation Plans

In connection with, but prior to, the Offering, our General Partner adopted the 2013 Midcoast Energy Partners, L.P. Long-Term Incentive Plan, or our LTIP, under which our General Partner may issue long-term equity based awards to directors, officers and employees of our General Partner or its affiliates, or to any consultants of our General Partner or other individuals who perform services for us. Directors and consultants who are not also employees of our General Partner or its affiliates will not be eligible to receive awards under the LTIP. We have filed a registration statement with the SEC registering the issuance of 3,750,000 Class A common units that are issuable pursuant to awards granted under our LTIP.

9. RELATED PARTY TRANSACTIONS

Intercorporate Services Agreement

We do not directly employ any of the individuals responsible for managing or operating our business. On November 13, 2013, we entered into an Intercorporate Services Agreement with EEP, pursuant to which EEP and its affiliates provides us with services as set forth in the agreement, which include such functions as management, accounting, operational and administrative personnel, among other such functions.

Under the Intercorporate Services Agreement, we reimburse EEP and its affiliates for the costs and expenses incurred in providing us with such services. The allocation methodology under which we reimburse EEP and its affiliates for the provision of general administrative and operational services to Midcoast Operating does not differ from the historical allocation methodology applied to Midcoast Operating under its prior services agreements with Enbridge and certain of its affiliates. EEP has agreed to reduce the amounts payable for general and administrative expenses that otherwise would have been allocable to Midcoast Operating by $25.0 million annually. As a result, for the nine month period ending September 30, 2014, we recognized $18.8 million as a reduction to "Due to general partner and affiliates" with the offset to "Noncontrolling interest" in our consolidated statements of financial position.

The following table presents the affiliate amounts incurred by us through EEP for services received pursuant to the Intercorporate Services Agreement and the services agreements with Enbridge and certain of its affiliates for periods prior to November 13, 2013. The amounts we incurred are reflected in our consolidated statements of income by category.

	For the three month period ended September 30,		For the nine month period ended September 30,	
	2014	2013	2014	2013
	(in millions)			
Operating and maintenance—affiliate	$26.3	$27.3	$ 81.0	$ 81.4
General and administrative—affiliate	23.4	25.0	68.7	73.0
Total	$49.7	$52.3	$149.7	$154.4

Enbridge and Enbridge Management and their respective affiliates allocated direct workforce costs to us for our construction projects of $4.0 million and $6.8 million as of September 30, 2014, and December 31, 2013, respectively, that we recorded as additions to “Property, plant and equipment, net” on our consolidated statements of financial position.

Affiliate Revenues and Purchases

We sell natural gas, NGLs and crude oil at market prices on the date of sale to Enbridge and its affiliates. The sales to Enbridge and its affiliates are presented in “Operating revenue—affiliate” on our consolidated statements of income. We also purchase natural gas, NGLs and crude oil at market prices on the date of purchase from Enbridge and its affiliates for sale to third parties. The purchases of natural gas, NGLs and crude oil from Enbridge and its affiliates are presented in “Cost of natural gas and natural gas liquids—affiliate” on our consolidated statements of income.

The following table presents our results for the three month periods ended September 30, 2014, and 2013 and the nine month periods ended September 30, 2014, and 2013 for operating revenues from sales to Enbridge and its affiliates and costs for natural gas, NGLs and crude oil purchases from Enbridge and its affiliates.

	For the three month period ended September 30,		For the nine month period ended September 30,	
	2014	2013	2014	2013
	(in millions)			
Operating revenue—affiliate	$50.6	$49.6	$174.7	$162.4
Cost of natural gas and natural gas liquids—affiliate	$29.7	$23.0	$ 98.3	$ 95.5

Routine purchases and sales with affiliates are settled monthly through MEP’s centralized treasury function at terms that are consistent with third-party transactions for the three and nine month periods ended September 30, 2014. For the three and nine month periods ended September 30, 2013, our Predecessor’s routine purchases and sales with affiliates were settled monthly through EEP’s centralized treasury function at terms that were consistent with third-party transactions. Routine purchases and sales with affiliates that have not yet been settled are included in “Due from general partner and affiliates” and “Due to general partner and affiliates” on our consolidated statements of financial position.

Related Party Transactions with Joint Venture

Included in “Cost of natural gas and natural gas liquids—affiliate” from above, for the three and nine month periods ended September 30, 2014, are $5.4 million and $16.8 million, respectively, of pipeline transportation and demand fees from Texas Express NGL system. We did not incur any fees from the Texas Express NGL system for the three and nine month periods ended September 30, 2013.

Our logistics and marketing business has made commitments to transport up to 120,000 barrels per day, or Bpd, of NGLs on the Texas Express NGL system from 2014 to 2023.

Partners' Capital Transactions

Midcoast Operating paid cash distributions totaling $83.3 million to EEP during the nine month period ended September 30, 2014, for its ownership interest in Midcoast Operating. In addition, we paid cash distributions totaling $8.1 million to EEP for the nine month period ended September 30, 2014, for its ownership interest in us. These amounts are reflected in "Distributions to noncontrolling interest" and "Distributions to partners", respectively, on our consolidated statements of cash flows.

Sale of Accounts Receivable

For the three and nine month periods ended September 30, 2014, we sold and derecognized $845.7 million and $2,702.2 million, respectively, of receivables to an indirect wholly owned subsidiary of Enbridge. For the three and nine month periods ended September 30, 2014, the cash proceeds were $845.5 million and $2,701.5 million, respectively, which was remitted to us through our centralized treasury system. As of September 30, 2014, $282.3 million of the receivables were outstanding and had not been collected on behalf of the Enbridge subsidiary.

Consideration for the receivables sold is equivalent to the carrying value of the receivables less a discount for credit risk. The difference between the carrying value of the receivables sold and the cash proceeds received is recognized in "General and administrative—affiliate" expense in our consolidated statements of income. For the three and nine month periods ended September 30, 2014, the expense stemming from the discount on the receivables sold was $0.2 million and $0.7 million, respectively.

As of September 30, 2014 and December 31, 2013, we had $5.9 million and $61.5 million, respectively, included in "Restricted cash" on our consolidated statements of financial position, consisting of cash collections related to the receivables sold that have yet to be remitted to the Enbridge subsidiary.

Allocated Interest

EEP incurred borrowing cost on behalf of our Predecessor, which we recognized to the extent we were able to capitalize such costs to our construction related projects. The interest cost we incurred was directly offset by the amount of interest we capitalized on outstanding construction projects. As of the three and nine month periods ended September 30, 2013, we had interest cost incurred and interest capitalized of $5.1 million and $16.6 million, respectively.

Derivative Transactions

Our Predecessor historically had related party derivative transactions executed on behalf of EEP that were contracted through our Predecessor prior to the Offering and were allocated to EEP. These transactions were contracted to hedge the forward price of EEP's crude oil length inherent to the operation of pipelines and to hedge EEP's interest payments of variable rate debt obligations. Subsequent to the Offering, these transactions were re-contracted through EEP and are no longer allocated from us. These historical transactions are included as part of Note 11. *Derivative Financial Instruments and Hedging Activities.*

10. COMMITMENTS AND CONTINGENCIES

Environmental Liabilities

We are subject to federal and state laws and regulations relating to the protection of the environment. Environmental risk is inherent to the operating activities of our gathering, processing and transportation and logistics and marketing businesses, and we are, at times, subject to environmental cleanup and enforcement actions. We manage this environmental risk through appropriate environmental policies and practices to minimize any impact our operations may have on the environment. To the extent that we are unable to recover payment for environmental liabilities from insurance or otherwise, we will be responsible for payment of liabilities arising from environmental incidents associated with the operating activities of our gathering, processing and transportation and logistics and marketing businesses. We continue to voluntarily monitor past leak sites on our systems for the purpose of assessing whether any remediation is required in light of current regulations. As of September 30, 2014, we had $0.2 million of accrued environmental liabilities included in "Other long-term liabilities." As of December 31, 2013, we did not record any environmental liabilities.

Legal and Regulatory Proceedings

We are a participant in a number of legal proceedings arising in the ordinary course of business. Some of these proceedings are not covered, in whole or in part, by insurance. While the ultimate outcome and impact to us cannot be predicted with certainty, we believe the outcome of all these proceedings will not, individually or in the aggregate, have a material adverse effect on our financial position, results of operations or cash flows. In addition, we are not aware of any significant legal or governmental proceedings against us, or contemplated to be brought against us, under the various environmental protection statutes to which we are subject.

11. DERIVATIVE FINANCIAL INSTRUMENTS AND HEDGING ACTIVITIES

Our net income and cash flows are subject to volatility stemming from fluctuations in commodity prices of natural gas, NGLs, condensate and fractionation margins. Fractionation margins represent the relative difference between the price we receive from NGL and condensate sales and the corresponding cost of natural gas we purchase for processing. Our exposure to commodity price risk exists within both of our segments. We use derivative financial instruments (i.e., futures, forwards, swaps, options, collars and other financial instruments with similar characteristics) to manage the risks associated with market fluctuations in commodity prices, as well as to reduce the volatility in our cash flows. Based on our risk management policies, all of our derivative financial instruments are employed in connection with an underlying asset, liability and/or forecasted transaction and are not entered into with the objective of speculating on commodity prices. We have hedged a portion of our exposure to variability in future cash flows associated with commodity price risks through 2017 in accordance with our risk management policies.

Accounting Treatment

Effective January 1, 2014, we elected to prospectively change the presentation of derivative assets and liabilities from a net basis to a gross basis in the Consolidated Statements of Financial Position. We adopted this change to provide more detailed information about the future economic benefits and obligations associated with our derivative activities in our Consolidated Statements of Financial Position. This change had no impact to the Consolidated Statements of Income, Net income (loss) per limited partner unit, or Partners' capital.

Non-Qualified Hedges

Many of our derivative financial instruments qualify for hedge accounting treatment as set forth in the authoritative accounting guidance. However, we have derivative financial instruments associated with our commodity activities where the hedge structure does not meet the requirements to apply hedge accounting. As a result, these derivative financial instruments do not qualify for hedge accounting and are referred to as non-qualifying. These non-qualifying derivative financial instruments are marked-to-market each period with the change in fair value included in "Cost of natural gas and natural gas liquids" or "Operating revenue" in our consolidated statements of income. These mark-to-market adjustments produce a degree of earnings volatility that can often be significant from period to period, but have no cash flow impact relative to changes in market prices. The cash flow impact occurs when the underlying physical transaction takes place in the future and the associated financial instrument contract settlement is made.

The following transaction types do not qualify for hedge accounting and contribute to volatility in our earnings and in our cash flows upon settlement:

Commodity Price Exposures:

- **Transportation**—In our logistics and marketing business, when we transport natural gas from one location to another, the pricing index used for natural gas sales is usually different from the pricing index used for natural gas purchases, which exposes us to market price risk relative to changes in those two indices. By entering into a basis swap, where we exchange one pricing index for another, we can effectively lock in the margin, representing the difference between the sales price and the purchase price, on the combined natural gas purchase and natural gas sale, removing any market price risk on the physical transactions. Although this represents a sound economic hedging strategy, the derivative financial instruments (i.e., the basis swaps) we use to manage the commodity price risk associated with these transportation contracts do not qualify for hedge accounting, since only the future margin has been fixed and not the future cash flow. As a result, the changes in fair value of these derivative financial instruments are recorded in earnings.
- **Storage**—In our logistics and marketing business, we use derivative financial instruments (i.e., natural gas, crude oil and NGL swaps) to hedge the relative difference between the injection price paid to purchase and store natural gas, crude oil and NGLs and the withdrawal price at which these commodities are sold from storage. The intent of these derivative financial instruments is to lock in the margin, representing the difference between the price paid for the natural gas, crude oil and NGLs injected and the price received upon withdrawal of these commodities from storage in a future period. We do not pursue cash flow hedge accounting treatment for these storage transactions since the underlying forecasted injection or withdrawal of these commodities may not occur in the period as originally forecast. This can occur because we have the flexibility to make changes in the underlying injection or withdrawal schedule, based on changes in market conditions. In addition, since the physical commodities are recorded at the lower of cost or market, timing differences can result when the derivative financial instrument is settled in a period that is different from the period the physical commodity is sold from storage. As a result, derivative financial instruments associated with our storage activities can increase volatility due to fluctuations in prices until the underlying transactions are settled or offset.
- **Optional Natural Gas Processing Volumes**—In our gathering, processing and transportation business, we use derivative financial instruments to hedge the volumes of NGLs produced from our natural gas processing facilities. Some of our natural gas contracts allow us the choice of processing natural gas when it is economical and to cease doing so when processing becomes uneconomic. We have entered into derivative financial instruments to fix the sales price of a portion of the NGLs that we produce at our discretion and to fix the associated purchase price of natural gas required for processing. We typically designate derivative financial instruments associated with NGLs we produce per contractual processing requirements as cash flow hedges when the processing of natural gas is probable of occurrence. However, we are precluded from designating the derivative financial instruments as qualifying hedges of the respective commodity price risk when the discretionary processing volumes are subject to change. As a result, our operating income is subject to increased volatility due to fluctuations in NGL prices until the underlying transactions are settled or offset.
- **NGL and Crude Oil Forward Contracts**—In our logistics and marketing business, we use forward contracts to fix the price of NGLs and crude oil we purchase and sell to meet the demands of our customers that sell and purchase NGLs and crude oil. A subgroup of physical NGL and crude oil contracts qualify for the normal purchases and normal sales, or NPNS, scope exception. All other forward contracts are being marked-to-market each period with the changes in fair value recorded in earnings. As a result, our operating income is subject to additional volatility associated with fluctuations in NGL and crude oil prices until the forward contracts are settled.

- **Natural Gas Forward Contracts—**In our logistics and marketing business, we use forward contracts to sell natural gas to our customers. A subgroup of our physical natural gas contracts qualify for the NPNS, scope exception. All other contracts are being marked-to-market each period with the changes in fair value recorded in earnings. As a result, our operating income is subject to additional volatility associated with the changes in fair value of these contracts.
- **Condensate**, **Natural Gas and NGL Options**—In our gathering, processing and transportation business, we use options to hedge the forecasted commodity exposure of our condensate, NGLs and natural gas. Although options can qualify for hedge accounting treatment, pursuant to the authoritative accounting guidance, we have elected non-qualifying treatment. As such, our option premiums are expensed as incurred. These derivatives are being marked-to-market, with the changes in fair value recorded to earnings each period. As a result, our operating income is subject to volatility due to movements in the prices of condensate, NGLs and natural gas until the underlying long-term transactions are settled.

In all instances related to the commodity exposures described above, the underlying physical purchase, storage and sale of the commodity is accounted for on a historical cost or net realizable value basis rather than on the mark-to-market basis we employ for the derivative financial instruments used to mitigate the commodity price risk associated with our storage and transportation assets. This difference in accounting (i.e., the derivative financial instruments are recorded at fair market value while the physical transactions are recorded at the lower of historical cost or net realizable value) can and has resulted in volatility in our reported net income, even though the economic margin is essentially unchanged from the date the transactions were consummated.

Derivative Positions

Our derivative financial instruments are included at their fair values in the consolidated statements of financial position as follows:

	September 30, 2014	December 31, 2013
	(in millions)	
Other current assets	$ 31.9	$ 10.3
Other assets, net	17.0	10.3
Accounts payable and other	(17.6)	(21.1)
Other long-term liabilities	(13.0)	(0.9)
Due from General Partner and affiliates	0.4	—
	$ 18.7	$ (1.4)

The changes in the assets and liabilities associated with our derivatives are primarily attributable to the effects of new derivative transactions we have entered at prevailing market prices, settlement of maturing derivatives and the change in forward market prices of our remaining hedges. Our portfolio of derivative financial instruments is largely comprised of natural gas, NGL and crude oil sales and purchase contracts.

The table below summarizes our derivative balances by counterparty credit quality (negative amounts represent our net obligations to pay the counterparty).

	September 30, 2014	December 31, 2013
	(in millions)	
Counterparty Credit Quality [(1)]		
AAA	$ 0.3	$ 0.2
AA	2.3	(2.1)
A	10.5	(1.1)
Lower than A	5.6	1.6
	$18.7	$(1.4)

(1) As determined by nationally-recognized statistical ratings organizations.

As the net value of our derivative financial instruments has increased in response to changes in forward commodity prices, our outstanding financial exposure to third parties has also increased. When credit thresholds are met pursuant to the terms of our International Swaps and Derivatives Association, Inc., or ISDA®, financial contracts, we have the right to require collateral from our counterparties. We include any cash collateral received in the balances listed above. As of September 30, 2014, and December 31, 2013, we were not holding any cash collateral on our asset exposures. When we are in a position of posting collateral to cover our counterparties' exposure to our non-performance, the collateral is provided through letters of credit, which are not reflected above.

At September 30, 2014, and December 31, 2013, we had credit concentrations in the following industry sectors, as presented below:

	September 30, 2014	December 31, 2013
	(in millions)	
United States financial institutions and investment banking entities	$ 7.3	$ 2.4
Non-United States financial institutions	4.8	0.1
Integrated oil companies	0.7	(1.6)
Other	5.9	(2.3)
	$18.7	$(1.4)

Gross derivative balances are presented below before the effects of collateral received or posted and without the effects of master netting arrangements. Both our assets and liabilities are adjusted for non-performance risk, which is statistically derived. This credit valuation adjustment model considers existing derivative asset and liability balances in conjunction with contractual netting and collateral arrangements, current market data such as credit default swap rates and bond spreads and probability of default assumptions to quantify an adjustment to fair value. For credit modeling purposes, collateral received is included in the calculation of our assets, while any collateral posted is excluded from the calculation of the credit adjustment. Our credit exposure for these over-the-counter, or OTC, derivatives is directly with our counterparty and continues until the maturity or termination of the contracts.

Effect of Derivative Instruments on the Consolidated Statements of Financial Position

	Financial Position Location	Asset Derivatives Fair Value at September 30, 2014	Asset Derivatives Fair Value at December 31, 2013	Liability Derivatives Fair Value at September 30, 2014	Liability Derivatives Fair Value at December 31, 2013
		(in millions)			
Derivatives designated as hedging instruments [1]					
Commodity contracts	Other current assets	$ 3.3	$ 2.0	$ —	$ (0.6)
Commodity contracts	Other assets	1.3	3.5	—	(0.5)
Commodity contracts	Accounts payable and other	—	1.9	(2.2)	(12.7)
Commodity contracts	Other long-term liabilities	—	0.6	(0.3)	(1.4)
		4.6	8.0	(2.5)	(15.2)
Derivatives not designated as hedging instruments					
Commodity contracts	Other current assets	28.6	9.0	—	(0.1)
Commodity contracts	Other assets	15.7	10.7	—	(3.4)
Commodity contracts	Accounts payable and other	—	5.4	(15.4)	(15.7)
Commodity contracts	Other long-term liabilities	—	—	(12.7)	(0.1)
Commodity contracts	Due from general partner and affiliates	0.4	—	—	—
		44.7	25.1	(28.1)	(19.3)
Total derivative instruments . .		$49.3	$33.1	$(30.6)	$(34.5)

(1) Includes items currently designated as hedging instruments. Excludes the portion of de-designated hedges which may have a component remaining in AOCI.

Accumulated Other Comprehensive Income

We record the change in fair value of our derivative financial instruments that qualify for and are designated as a cash flow hedge, which is a hedge of a forecasted transaction or future cash flows, in AOCI, a component of "Partners' capital," until the underlying hedged transaction occurs. Upon settlement of the designated cash flow hedges, gains (losses) are reclassified to earnings. Also included in AOCI, as of September 30, 2014, are derivative financial instruments that qualified for and were classified as cash flow hedges of forecasted transactions that were subsequently de-designated, settled, or terminated. These transactions are reclassified to earnings over the periods during which the originally hedged forecasted transactions affect earnings.

During the nine month period ended September 30, 2014, unrealized commodity hedge losses of $0.2 million were de-designated as a result of the hedges no longer meeting hedge accounting criteria. We estimate that approximately $1.5 million, representing unrealized net gains from our cash flow hedging activities based on pricing and positions at September 30, 2014, will be reclassified from AOCI to earnings during the next 12 months.

We used a portion of the net proceeds of our September 30, 2014 debt issuance of $400 million to settle treasury locks we entered in July 2014 to hedge the interest payments on a portion of these obligations. The $0.9 million settlement amount is being amortized from AOCI to interest expense over the 5 year original hedge term.

Effect of Derivative Instruments on the Consolidated Statements of Income and Accumulated Other Comprehensive Income

Derivatives in Cash Flow Hedging Relationships	Amount of Gain (Loss) Recognized in AOCI on Derivative (Effective Portion)	Location of Gain (Loss) Reclassified from AOCI to Earnings (Effective Portion)	Amount of Gain (Loss) Reclassified from AOCI to Earnings (Effective Portion)	Location of Gain (Loss) Recognized in Earnings on Derivative (Ineffective Portion and Amount Excluded from Effectiveness Testing) [1]	Amount of Gain (Loss) Recognized in Earnings on Derivative (Ineffective Portion and Amount Excluded from Effectiveness Testing) [1]
		(in millions)			
For the three month period ended September 30, 2014					
Commodity contracts . .	$ 11.2	Cost of natural gas and natural gas liquids	$ (2.1)	Cost of natural gas and natural gas liquids	$ 0.9
Total	$ 11.2		$ (2.1)		$ 0.9
For the three month period ended September 30, 2013					
Commodity contracts . .	$(17.2)	Cost of natural gas and natural gas liquids	$ (0.6)	Cost of natural gas and natural gas liquids	$(0.5)
Total	$(17.2)		$ (0.6)		$(0.5)
For the nine month period ended September 30, 2014					
Commodity contracts . .	$ 7.9	Cost of natural gas and natural gas liquids	$(12.4)	Cost of natural gas and natural gas liquids	$ 1.5
Total	$ 7.9		$(12.4)		$ 1.5
For the nine month period ended September 30, 2013					
Commodity contracts . .	$ (8.8)	Cost of natural gas and natural gas liquids	$ 3.0	Cost of natural gas and natural gas liquids	$ 1.8
Total	$ (8.8)		$ 3.0		$ 1.8

(1) Includes only the ineffective portion of derivatives that are designated as hedging instruments and does not include net gains or losses associated with derivatives that do not qualify for hedge accounting treatment.

Components of Accumulated Other Comprehensive Income/(Loss)

	Cash Flow Hedges
	(in millions)
Balance at December 31, 2013	$(3.1)
Other Comprehensive Income before reclassifications [1] [2]	(1.8)
Amounts reclassified from AOCI [3] [4]	5.1
Net other comprehensive loss	$ 3.3
Balance at September 30, 2014	$ 0.2

(1) Excludes NCI loss of $2.9 million reclassified from AOCI at September 30, 2014.
(2) Excludes NCI gain of $0.9 million reclassified from AOCI related to the acquisition of additional interests in MOLP at September 30, 2014.
(3) Excludes NCI gain of $7.3 million reclassified from AOCI at September 30, 2014.
(4) For additional details on the amounts reclassified from AOCI, reference the *Reclassifications from Accumulated Other Comprehensive Income* table below.

Reclassifications from Accumulated Other Comprehensive Income

	For the three month period ended September 30,		For the nine month period ended September 30,	
	2014	2013	2014	2013
	(in millions)			
Losses (gains) on cash flow hedges:				
Commodity Contracts [1] [2]	$1.1	$0.6	$5.1	$(3.0)
Total Reclassifications from AOCI	$1.1	$0.6	$5.1	$(3.0)

(1) Loss (gain) reported within "Cost of natural gas and natural gas liquids" in the consolidated statements of income.

(2) Excludes NCI gain of $1.0 million and $7.3 million reclassified from AOCI for the three and nine month periods ended September 30, 2014.

Effect of Derivative Instruments on Consolidated Statements of Income

		For the three month period ended September 30,		For the nine month period ended September 30,	
		2014	2013	2014	2013 [4]
Derivatives Not Designated as Hedging Instruments	Location of Gain or (Loss) Recognized in Earnings [1]	Amount of Gain or (Loss) Recognized in Earnings [2]		Amount of Gain or (Loss) Recognized in Earnings [2]	
		(in millions)			
Commodity contracts	Cost of natural gas and natural gas liquids [3]	$ 9.5	$(28.1)	$ (9.9)	$ (8.9)
Commodity contracts	Operating revenue	7.7	(6.2)	10.8	(6.2)
Commodity contracts	Operating revenue — affiliate	(0.1)	—	0.4	—
Total		$17.1	$(34.3)	$ 1.3	$(15.1)

(1) Does not include settlements associated with derivative instruments that settle through physical delivery.

(2) Includes only net gains or losses associated with those derivatives that do not qualify for hedge accounting treatment and does not include the ineffective portion of derivatives that are designated as hedging instruments.

(3) Includes settlements gains and (losses) of $0.1 million and $(0.2) million for the three month periods ended September 30, 2014, and 2013, respectively, and $(8.6) million and $0.5 million for the nine month periods ended September 30, 2014, and 2013, respectively.

(4) Includes both affiliate and third party transactions.

We record the fair market value of our derivative financial and physical instruments in the consolidated statements of financial position as current and long-term assets or liabilities on a gross basis. However, the terms of the ISDA®, which governs our financial contracts and our other master netting agreements, allow the parties to elect in respect of all transactions under the agreement, in the event of a default and upon notice to the defaulting party, for the non-defaulting party to set-off all settlement payments, collateral held and any other obligations (whether or not then due), which the non-defaulting party owes to the defaulting party. The effect of the rights of set-off are outlined below.

Offsetting of Financial Assets and Derivative Assets

	As of September 30, 2014				
	Gross Amount of Recognized Assets	Gross Amount Offset in the Statement of Financial Position	Net Amount of Assets Presented in the Statement of Financial Position	Gross Amount Not Offset in the Statement of Financial Position	Net Amount
	(in millions)				
Description:					
Derivatives	$49.3	$ —	$49.3	$(24.6)	$24.7
Total	$49.3	$ —	$49.3	$(24.6)	$24.7

	As of December 31, 2013				
	Gross Amount of Recognized Assets	Gross Amount Offset in the Statement of Financial Position	Net Amount of Assets Presented in the Statement of Financial Position	Gross Amount Not Offset in the Statement of Financial Position	Net Amount
			(in millions)		
Description:					
Derivatives	$33.1	$(12.5)	$20.6	$(1.9)	$18.7
Total	$33.1	$(12.5)	$20.6	$(1.9)	$18.7

Offsetting of Financial Liabilities and Derivative Liabilities

	As of September 30, 2014				
	Gross Amount of Recognized Liabilities	Gross Amount Offset in the Statement of Financial Position	Net Amount of Liabilities Presented in the Statement of Financial Position	Gross Amount Not Offset in the Statement of Financial Position	Net Amount
			(in millions)		
Description:					
Derivatives	$(30.6)	$ —	$(30.6)	$24.6	$(6.0)
Total	$(30.6)	$ —	$(30.6)	$24.6	$(6.0)

	As of December 31, 2013				
	Gross Amount of Recognized Liabilities	Gross Amount Offset in the Statement of Financial Position	Net Amount of Liabilities Presented in the Statement of Financial Position	Gross Amount Not Offset in the Statement of Financial Position	Net Amount
			(in millions)		
Description:					
Derivatives	$(34.5)	$12.5	$(22.0)	$1.9	$(20.1)
Total	$(34.5)	$12.5	$(22.0)	$1.9	$(20.1)

Inputs to Fair Value Derivative Instruments

The following table sets forth by level within the fair value hierarchy our financial assets and liabilities that were accounted for at fair value on a recurring basis as of September 30, 2014, and December 31, 2013. We classify financial assets and liabilities in their entirety based on the lowest level of input that is significant to the fair value measurement. Our assessment of the significance of a particular input to the fair value measurement requires judgment and may affect our valuation of the financial assets and liabilities and their placement within the fair value hierarchy.

	September 30, 2014				December 31, 2013			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
				(in millions)				
Commodity contracts:								
Financial	$ —	$ 3.9	$ 1.8	$ 5.7	$ —	$(3.4)	$(6.9)	$(10.3)
Physical	—	—	7.7	7.7	—	—	0.5	0.5
Commodity options	—	—	5.3	5.3	—	—	8.4	8.4
Total	$ —	$ 3.9	$14.8	$18.7	$ —	$(3.4)	$ 2.0	$ (1.4)

Qualitative Information about Level 2 Fair Value Measurements

We categorize, as Level 2, the fair value of assets and liabilities that we measure with either directly or indirectly observable inputs as of the measurement date, where pricing inputs are other than quoted prices in active markets for the identical instrument. This category includes both OTC transactions valued using exchange traded pricing information in addition to assets and liabilities that we value using either models or other valuation methodologies derived from observable market data. These models are primarily industry-standard models that consider various inputs including: (1) quoted prices for assets and liabilities; (2) time value; and (3) current market and contractual prices for the underlying instruments, as well as other relevant economic measures. Substantially all of these inputs are observable in the marketplace throughout the full term of the assets and liabilities, can be derived from observable data, or are supported by observable levels at which transactions are executed in the marketplace.

Qualitative Information about Level 3 Fair Value Measurements

Data from pricing services and published indices are used to value our Level 3 derivative instruments, which are fair-valued on a recurring basis. We may also use these inputs with internally developed methodologies that result in our best estimate of fair value. The inputs listed in the table below would have a direct impact on the fair values of the listed instruments. The significant unobservable inputs used in the fair value measurement of the commodity derivatives (Natural Gas, NGLs and Crude Oil) are forward commodity prices. The significant unobservable inputs used in determining the fair value measurement of options are price and volatility. Increases/(decreases) in the forward commodity price in isolation would result in significantly higher/(lower) fair values for long positions, with offsetting impacts to short positions. Increases/(decreases) in volatility would increase/(decrease) the value for the holder of the option. Generally, a change in the estimate of forward commodity prices is unrelated to a change in the estimate of volatility of prices. An increase to the credit valuation adjustment would decrease the fair value of the positions.

Quantitative Information About Level 3 Fair Value Measurements

Contract Type	Fair Value at [2] September 30, 2014	Valuation Technique	Unobservable Input	Range [1] Lowest	Highest	Weighted Average	Units
	(in millions)						
Commodity Contracts—Financial							
Natural Gas	$ (0.6)	Market Approach	Forward Gas Price	3.49	4.74	4.01	MMBtu
NGLs	$ 2.4	Market Approach	Forward NGL Price	0.24	1.98	1.18	Gal
Commodity Contracts—Physical							
Natural Gas	$ 1.8	Market Approach	Forward Gas Price	2.03	4.83	4.04	MMBtu
Crude Oil	$ (1.5)	Market Approach	Forward Crude Oil Price	83.03	94.98	90.86	Bbl
NGLs	$ 7.4	Market Approach	Forward NGL Price	0.23	2.05	1.08	Gal
Commodity Options							
Natural Gas, Crude and NGLs	$ 5.3	Option Model	Option Volatility	14%	40%	28%	
Total Fair Value	$14.8						

(1) Prices are in dollars per Millions of British Thermal Units, or MMBtu, for Natural Gas, dollars per Gallon, or Gal, for NGLs and dollars per barrel, or Bbl, for Crude Oil.

(2) Fair values are presented in millions of dollars and include credit valuation adjustments of approximately $0.1 million of losses.

Quantitative Information About Level 3 Fair Value Measurements

Contract Type	Fair Value at December 31, 2013 [(2)]	Valuation Technique	Unobservable Input	Range [(1)] Lowest	Highest	Weighted Average	Units
	(in millions)						
Commodity Contracts—Financial							
Natural Gas	$ —	Market Approach	Forward Gas Price	3.64	4.41	4.14	MMBtu
NGLs	$ (6.9)	Market Approach	Forward NGL Price	1.00	2.13	1.38	Gal
Commodity Contracts—Physical							
Natural Gas	$ 1.1	Market Approach	Forward Gas Price	3.36	4.82	4.15	MMBtu
Crude Oil	$ (0.5)	Market Approach	Forward Crude Oil Price	86.37	103.04	97.24	Bbl
NGLs	$ (0.1)	Market Approach	Forward NGL Price	0.02	2.19	0.95	Gal
Commodity Options							
Natural Gas, Crude and NGLs	$ 8.4	Option Model	Option Volatility	18%	44%	28%	
Total Fair Value	$ 2.0						

(1) Prices are in dollars per MMBtu for Natural Gas, dollars per Gal for NGLs and dollars per Bbl for Crude Oil.

(2) Fair values include credit valuation adjustments of approximately $0.1 million of gains.

Level 3 Fair Value Reconciliation

The table below provides a reconciliation of changes in the fair value of our Level 3 financial assets and liabilities measured on a recurring basis from January 1, 2014, to September 30, 2014. No transfers of assets between any of the Levels occurred during the period.

	Commodity Financial Contracts	Commodity Physical Contracts	Commodity Options	Total
	(in millions)			
Beginning balance as of January 1, 2014	$ (6.9)	$ 0.5	$ 8.4	$ 2.0
Transfer out of Level 3 [(1)]	—	—	—	—
Gains or losses:				
Included in earnings	(3.9)	10.8	(1.1)	5.8
Included in other comprehensive income	(0.2)	—	—	(0.2)
Purchases, issuances, sales and settlements:				
Purchases	—	—	0.4	0.4
Sales	—	—	(1.6)	(1.6)
Settlements [(2)]	12.8	(3.6)	(0.8)	8.4
Ending balance as of September 30, 2014	$ 1.8	$ 7.7	$ 5.3	$14.8
Amount of changes in net assets attributable to the change in unrealized gains or losses related to assets still held at the reporting date	$ 2.4	$ 7.1	$(1.8)	$ 7.7
Amounts reported in operating revenue	$ —	$11.2	$—	$11.2

(1) Our policy is to recognize transfers as of the last day of the reporting period.

(2) Settlements represent the realized portion of forward contracts.

Fair Value Measurements of Commodity Derivatives

The following table provides summarized information about the fair values of expected cash flows of our outstanding commodity based swaps and physical contracts at September 30, 2014, and December 31, 2013.

	At September 30, 2014						At December 31, 2013	
			Wtd. Average Price (2)		Fair Value (3)		Fair Value (3)	
	Commodity	Notional (1)	Receive	Pay	Asset	Liability	Asset	Liability
					(in millions)			
Portion of contracts maturing in 2014								
Swaps								
Receive variable/pay fixed	Natural Gas	668,692	$ 4.00	$ 3.91	$ 0.1	$ —	$ —	$ —
	NGL	623,000	$56.02	$56.64	$ 0.3	$ (0.7)	$ 0.6	$ (0.4)
	Crude Oil	95,000	$89.87	$92.56	$ —	$ (0.3)	$ —	$ —
Receive fixed/pay variable	Natural Gas	2,380,100	$ 4.26	$ 4.09	$ 0.5	$ (0.1)	$ 0.1	$ (1.0)
	NGL	2,021,140	$51.91	$50.97	$ 3.7	$ (1.8)	$ 4.8	$(12.7)
	Crude Oil	330,160	$92.67	$90.11	$ 1.2	$ (0.4)	$ 0.3	$ (5.4)
Receive variable/pay variable	Natural Gas	19,562,500	$ 4.03	$ 4.02	$ 0.6	$ (0.5)	$ 0.6	$ (0.1)
Physical Contracts								
Receive variable/pay fixed	Natural Gas	313,224	$ 3.89	$ 1.23	$ 0.8	$ —	$ —	$ —
	NGL	550,000	$42.40	$43.88	$ —	$ (0.8)	$ 0.9	$ (0.9)
	Crude Oil	45,000	$90.85	$93.90	$ —	$ (0.1)	$ —	$ —
Receive fixed/pay variable	Natural Gas	185,506	$ 4.03	$ 3.97	$ —	$ —	$ —	$ —
	NGL	3,504,872	$39.20	$37.85	$ 5.1	$ (0.4)	$ 0.4	$ (2.6)
	Crude Oil	75,000	$93.08	$90.62	$ 0.2	$ —	$ —	$ (0.4)
Receive variable/pay variable	Natural Gas	72,613,470	$ 4.02	$ 4.02	$ 0.9	$ (1.1)	$ 0.9	$ (0.4)
	NGL	10,947,422	$42.80	$42.61	$ 2.7	$ (0.6)	$ 5.8	$ (3.7)
	Crude Oil	758,914	$88.26	$90.52	$ 0.8	$ (2.5)	$ 1.1	$ (1.2)
Portion of contracts maturing in 2015								
Swaps								
Receive variable/pay fixed	Natural Gas	316,837	$ 3.91	$ 3.93	$ —	$ —	$ —	$ —
	NGL	145,850	$72.56	$78.20	$ —	$ (0.8)	$ —	$ —
	Crude Oil	456,000	$87.81	$92.94	$ —	$ (2.3)	$ —	$ —
Receive fixed/pay variable	Natural Gas	809,761	$ 4.56	$ 4.21	$ 0.3	$ —	$ —	$ —
	NGL	1,024,750	$54.42	$52.36	$ 3.1	$ (1.0)	$ 1.5	$ (1.1)
	Crude Oil	788,150	$94.02	$87.79	$ 4.9	$ —	$ 1.7	$ —
Receive variable/pay variable	Natural Gas	42,725,000	$ 3.92	$ 3.94	$ 0.8	$ (1.7)	$ 0.1	$ —
Physical Contracts								
Receive variable/pay fixed	NGL	95,000	$46.73	$48.37	$ —	$ (0.2)	$ —	$ —
Receive fixed/pay variable	NGL	586,394	$49.38	$47.79	$ 1.0	$ —	$ —	$ —
Receive variable/pay variable	Natural Gas	108,991,322	$ 4.05	$ 4.05	$ 1.4	$ (0.7)	$ 0.5	$ (0.1)
	NGL	3,094,719	$61.40	$61.19	$ 1.2	$ (0.5)	$ —	$ —
	Crude Oil	151,000	$90.30	$88.89	$ 0.2	$ —	$ —	$ —
Portion of contracts maturing in 2016								
Swaps								
Receive fixed/pay variable	Crude Oil	68,250	$90.89	$86.36	$ 0.3	$ —	$ 0.7	$ —
Receive variable/pay fixed	Crude Oil	68,250	$86.36	$90.00	$ —	$ (0.2)	$ —	$ —
	Natural Gas	181,435	$ 3.78	$ 3.85	$ —	$ —	$ —	$ —
Receive variable/pay variable	Natural Gas	12,027,000	$ 3.96	$ 3.98	$ 0.1	$ (0.3)	$ —	$ —
Physical Contracts								
Receive variable/pay variable	Natural Gas	34,560,879	$ 4.06	$ 4.05	$ 0.7	$ (0.4)	$ 0.1	$ —
Portion of contracts maturing in 2017								
Physical Contracts								
Receive variable/pay variable	Natural Gas	14,299,743	$ 4.27	$ 4.26	$ 0.2	$ (0.1)	$ —	$ —

(1) Volumes of natural gas are measured in MMBtu, whereas volumes of NGL and crude oil are measured in Bbl.

(2) Weighted average prices received and paid are in $/MMBtu for natural gas and $/Bbl for NGL and crude oil.

(3) The fair value is determined based on quoted market prices at September 30, 2014, and December 31, 2013, respectively, discounted using the swap rate for the respective periods to consider the time value of money. Fair values are presented in millions of dollars and exclude credit valuation adjustments of approximately $0.1 million of losses at September 30, 2014 and $0.1 million of gains at December 31, 2013.

The following table provides summarized information about the fair values of expected cash flows of our outstanding commodity options at September 30, 2014, and December 31, 2013.

	At September 30, 2014						At December 31, 2013	
					Fair Value (3)		Fair Value (3)	
	Commodity	Notional (1)	Strike Price (2)	Market Price (2)	Asset	Liability	Asset	Liability
						(in millions)		
Portion of option contracts maturing in 2014								
Puts (purchased) . .	Natural Gas	1,104,000	$ 3.90	$ 4.10	$ 0.1	$ —	$ 0.7	$ —
	NGL	193,200	$54.79	$52.43	$ 0.9	$ —	$ 2.9	$ —
Calls (written)	NGL	115,000	$60.92	$54.59	$ —	$ (0.1)	$ —	$ (1.0)
Puts (written)	Natural Gas	1,104,000	$ 3.90	$ 4.10	$ —	$ (0.1)	$ —	$ (0.5)
	NGL	32,200	$66.36	$51.70	$ —	$ (0.5)	$ —	$ —
Calls (purchased)	NGL	46,000	$50.40	$43.84	$ —	$ —	$ —	$ —
Portion of option contracts maturing in 2015								
Puts (purchased) . .	Natural Gas	4,015,000	$ 3.90	$ 4.00	$ 1.4	$ —	$ 1.7	$ —
	NGL	1,350,500	$48.75	$50.62	$ 5.5	$ —	$ 6.0	$ —
	Crude Oil	547,500	$85.42	$87.76	$ 2.3	$ —	$ 1.8	$ —
Calls (written)	Natural Gas	1,277,500	$ 5.05	$ 4.00	$ —	$ (0.1)	$ —	$ (0.3)
	NGL	529,250	$55.18	$50.29	$ —	$ (1.7)	$ —	$ (1.0)
	Crude Oil	547,500	$91.75	$87.76	$ —	$ (2.1)	$ —	$ (1.9)
Puts (written)	Natural Gas	4,015,000	$ 3.90	$ 4.00	$ —	$ (1.4)	$ —	$ —
Calls (purchased)	Natural Gas	1,277,500	$ 5.05	$ 4.00	$ 0.1	$ —	$ —	$ —
Portion of option contracts maturing in 2016								
Puts (purchased) . .	Natural Gas	1,647,000	$ 3.75	$ 4.08	$ 0.5	$ —	$ —	$ —
	NGL	1,281,000	$41.82	$44.06	$ 6.5	$ —	$ —	$ —
	Crude Oil	439,200	$80.00	$85.93	$ 2.0	$ —	$ —	$ —
Calls (written)	Natural Gas	1,647,000	$ 4.98	$ 4.08	$ —	$ (0.3)	$ —	$ —
	NGL	1,281,000	$48.59	$44.06	$ —	$ (5.6)	$ —	$ —
	Crude Oil	439,200	$92.25	$85.93	$ —	$ (2.2)	$ —	$ —

(1) Volumes of natural gas are measured in MMBtu, whereas volumes of NGL and crude oil are measured in Bbl.

(2) Strike and market prices are in $/MMBtu for natural gas and in $/Bbl for NGL and crude oil.

(3) The fair value is determined based on quoted market prices at September 30, 2014, and December 31, 2013, respectively, discounted using the swap rate for the respective periods to consider the time value of money. Fair values are presented in millions of dollars and exclude any credit valuation adjustments at September 30, 2014.

12. INCOME TAXES

We are not a taxable entity for United States federal income tax purposes or for the majority of states that impose an income tax. Taxes on our net income generally are borne by our unitholders through the allocation of taxable income. Our income tax expense results from the enactment of state income tax laws by the State of Texas that apply to entities organized as partnerships. Our income tax expense is based upon many but not all items included in net income.

We computed our income tax expense by applying a Texas state income tax rate to modified gross margin. Our Texas state income tax rate was 0.5% and 0.4% for the nine month periods ended September 30, 2014 and 2013, respectively. Our income tax expense is $0.9 million and $0.6 million for the three month periods ended September 30, 2014 and 2013, respectively, and $2.7 million and $8.9 million for the nine month periods ended September 30, 2014 and 2013, respectively.

At September 30, 2014 and December 31, 2013, we have included a current income tax payable of $1.1 million and $1.0 million, respectively, in “Property and other taxes payable” on our consolidated statements of financial position. In addition, at September 30, 2014 and December 31, 2013, we have included a deferred income tax payable of $12.5 million and $11.1 million, respectively, in "Other long-term liabilities" on our consolidated statements of financial position to reflect the tax associated with the difference between the net basis in assets and liabilities for financial and state tax reporting.

13. SEGMENT INFORMATION

Our business is divided into operating segments, defined as components of the enterprise, about which financial information is available and evaluated regularly by our Chief Operating Decision Maker, collectively comprised of our senior management, in deciding how resources are allocated and performance is assessed.

Each of our reportable segments is a business unit that offers different services and products that is managed separately, since each business segment requires different operating strategies. We conduct our business through two distinct reporting segments:

- Gathering, Processing and Transportation; and
- Logistics and Marketing.

The following tables present certain financial information relating to our business segments and corporate activities:

	For the three month period ended September 30, 2014			
	Gathering, Processing and Transportation	Logistics and Marketing	Corporate [1]	Total
	(in millions)			
Total revenue	$646.3	$1,252.4	$ —	$1,898.7
Less: Intersegment revenue	484.9	14.4	—	499.3
Operating revenue	161.4	1,238.0	—	1,399.4
Cost of natural gas and natural gas liquids	20.7	1,217.5	—	1,238.2
Segment gross margin	140.7	20.5	—	161.2
Operating and maintenance	64.9	15.7	—	80.6
General and administrative	21.3	3.1	1.5	25.9
Depreciation and amortization	35.5	4.0	—	39.5
	121.7	22.8	1.5	146.0
Operating income (loss)	19.0	(2.3)	(1.5)	15.2
Interest expense, net	—	—	3.6	3.6
Other income	5.3 [2]	—	—	5.3
Income (loss) before income tax expense	24.3	(2.3)	(5.1)	16.9
Income tax expense	—	—	0.9	0.9
Net income (loss)	$ 24.3	$ (2.3)	$ (6.0)	$ 16.0
Less: Net loss attributable to:				
Noncontrolling interest	—	—	9.7	9.7
Net income (loss) attributable to general and limited partner ownership interests in Midcoast Energy Partners, L.P.	$ 24.3	$ (2.3)	$(15.7)	$ 6.3

(1) Corporate consists of income taxes and interest expense, which are not allocated to the business segments.

(2) Other income for our Gathering, Processing and Transportation segment includes our long-term equity investment in the Texas Express NGL system.

	For the three month period ended September 30, 2013			
	Gathering, Processing and Transportation	Logistics and Marketing	Corporate [1]	Total
	(in millions)			
Total revenue	$668.2	$1,228.8	$—	$1,897.0
Less: Intersegment revenue	496.8	19.3	—	516.1
Operating revenue	171.4	1,209.5	—	1,380.9
Cost of natural gas and natural gas liquids	33.5	1,210.8	—	1,244.3
Segment gross margin	137.9	(1.3)	—	136.6
Operating and maintenance	71.0	17.7	—	88.7
General and administrative	22.1	2.9	—	25.0
Depreciation and amortization	34.1	1.7	—	35.8
	127.2	22.3	—	149.5
Operating income (loss)	10.7	(23.6)	—	(12.9)
Income (loss) before income tax expense	10.7	(23.6)	—	(12.9)
Income tax expense	—	—	0.6	0.6
Net income (loss)	$ 10.7	$ (23.6)	$(0.6)	$ (13.5)

(1) Corporate consists of income taxes, which are not allocated to the business segments.

	As of and for the nine month period ended September 30, 2014			
	Gathering, Processing and Transportation	Logistics and Marketing	Corporate [1]	Total
	(in millions)			
Total revenue	$2,065.3	$3,981.2	$ —	$6,046.5
Less: Intersegment revenue	1,531.2	72.2	—	1,603.4
Operating revenue	534.1	3,909.0	—	4,443.1
Cost of natural gas and natural gas liquids	155.6	3,831.1	—	3,986.7
Segment gross margin	378.5	77.9	—	456.4
Operating and maintenance	196.5	49.8	0.2	246.5
General and administrative	62.4	8.8	3.5	74.7
Depreciation and amortization	105.4	7.9	—	113.3
	364.3	66.5	3.7	434.5
Operating income (loss)	14.2	11.4	(3.7)	21.9
Interest expense, net	—	—	9.7	9.7
Other income	6.4 [2]	—	—	6.4
Income (loss) before income tax expense	20.6	11.4	(13.4)	18.6
Income tax expense	—	—	2.7	2.7
Net income (loss)	20.6	11.4	(16.1)	15.9
Less: Net income attributable to:				
Noncontrolling interest	—	—	13.8	13.8
Net income (loss) attributable to general and limited partner ownership interests in Midcoast Energy Partners, L.P.	$ 20.6	$ 11.4	$ (29.9)	$ 2.1
Total assets	$4,955.8 [3]	$ 499.2	$130.2	$5,585.2
Capital expenditures (excluding acquisitions)	$ 149.8	$ 8.6	$ 3.2	$ 161.6

(1) Corporate consists of income taxes and interest expense, which are not allocated to the business segments.

(2) Other income for our Gathering, Processing and Transportation segment includes our long-term equity investment in the Texas Express NGL system which began recognizing operating costs during the fourth quarter of 2013.

(3) Totals assets for our Gathering, Processing and Transportation segment includes our long-term equity investment in the Texas Express NGL system.

	As of and for the nine month period ended September 30, 2013			
	Gathering, Processing and Transportation	Logistics and Marketing	Corporate [1]	Total
	(in millions)			
Total revenue	$2,034.0	$3,580.0	$ —	$5,614.0
Less: Intersegment revenue	1,491.0	72.7	—	1,563.7
Operating revenue	543.0	3,507.3	—	4,050.3
Cost of natural gas and natural gas liquids	101.7	3,451.7	—	3,553.4
Segment gross margin	441.3	55.6	—	496.9
Operating and maintenance	208.2	54.9	—	263.1
General and administrative	64.6	8.5	—	73.1
Depreciation and amortization	101.3	5.0	—	106.3
	374.1	68.4	—	442.5
Operating income (loss)	67.2	(12.8)	—	54.4
Other income	—	—	0.2	0.2
Income (loss) before income tax expense	67.2	(12.8)	0.2	54.6
Income tax expense	—	—	8.9	8.9
Net income (loss)	$ 67.2	$ (12.8)	$ (8.7)	$ 45.7
Total assets	$4,829.3 [2]	$ 557.4	$54.7	$5,441.4
Capital expenditures (excluding acquisitions)	$ 177.9	$ 14.0	$13.9	$ 205.8

(1) Corporate consists of income taxes, which are not allocated to the business segments.

(2) Totals assets for our Gathering, Processing and Transportation segment includes our long-term equity investment in the Texas Express NGL system.

14. SUPPLEMENTAL CASH FLOW INFORMATION

In the "Cash used in investing activities" section of the consolidated statements of cash flows, we exclude changes that did not affect cash. The following is a reconciliation of cash used for additions to property, plant and equipment to total capital expenditures (excluding "Investment in joint ventures"):

	For the nine month period ended September 30,	
	2014	2013
	(in millions)	
Additions to property, plant and equipment	$166.6	$206.6
Decrease in construction payables	(5.0)	(0.8)
Total capital expenditures (excluding "Investment in joint ventures")	$161.6	$205.8

15. RECENT ACCOUNTING PRONOUNCEMENTS NOT YET ADOPTED

In April 2014, the Financial Accounting Standards Board, or FASB, issued Accounting Standards Update No. 2014-08 that changes the criteria and requires expanded disclosures for reporting discontinued operations. This accounting update is effective for annual and interim periods beginning after December 15, 2014, and is to be applied prospectively. We do not expect that the adoption of this pronouncement will have a material impact on our consolidated financial statements.

In May 2014, the FASB issued Accounting Standards Update No. 2014-09 that outlines a single comprehensive model for entities to use in accounting for revenue arising from contracts with customers and supersedes most current revenue recognition guidance, including industry-specific guidance. This accounting update is effective for annual and interim periods beginning on or after December 15, 2016, and may be applied on either a full or modified retrospective basis. We are currently evaluating which transition approach we will apply and the impact that this pronouncement will have on our consolidated financial statements.

In August 2014, the FASB issued Accounting Standards Update No. 2014-15 which provides guidance on determining when and how to disclose going-concern uncertainties in the financial statements. The new standard requires management to perform interim and annual assessments of an entity's ability to continue as a going concern within one year of the date the financial statements are issued. An entity must provide certain disclosures if conditions or events raise substantial doubt about the entity's ability to continue as a going concern. This accounting update is effective for annual and interim periods beginning on or after December 15, 2016, with early adoption permitted. We do not expect that the adoption of this pronouncement will have a material impact on our consolidated financial statements.

16. SUBSEQUENT EVENTS

Termination of Working Capital Credit Facility

On October 30, 2014, the board of directors of Midcoast Holdings, acting in its capacity as the General Partner of MEP, on behalf of Midcoast OLP GP, L.L.C., acting in its capacity as the general partner of Midcoast Operating approved the termination of the working capital credit facility with EEP as the lender. Midcoast Operating has exercised its right under the working capital facility to terminate the agreement upon 30-days' notice, and such termination is expected to occur in the fourth quarter. At the time of the termination, there is not expected to be any outstanding borrowings under this facility.

Distribution to Partners

On October 30, 2014, the board of directors of Midcoast Holdings, acting in its capacity as the General Partner of MEP, declared a cash distribution payable to our partners on November 14, 2014. The distribution will be paid to unitholders of record as of November 7, 2014, of our available cash of $15.6 million at September 30, 2014, or $0.3375 per limited partner unit. We will pay $7.2 million to our public Class A common unitholders, while $8.4 million in the aggregate will be paid to EEP with respect to its Class A common units and subordinated units and Midcoast Holdings, L.L.C., with respect to its general partner interest.

Midcoast Operating Distribution

On October 30, 2014, the general partner of Midcoast Operating, acting in its capacity as the General Partner of Midcoast Operating, declared a cash distribution by Midcoast Operating payable to its partners of record as of November 7, 2014. Midcoast Operating will pay $13.5 million to us and $12.6 million to EEP.

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

The following discussion and analysis of our financial condition and results of operations is based on and should be read in conjunction with our consolidated financial statements and the accompanying notes included in Item 1. *Financial Statements* and in conjunction with the audited consolidated financial statements and accompanying footnotes in our Annual Report on Form 10-K for the year ended December 31, 2013, as filed with the SEC on February 18, 2014.

On November 13, 2013, we completed our initial public offering, or the Offering, of Class A common units representing limited partner interests in the Partnership. Unless the context otherwise requires, references in this report to the Predecessor, we, our, us, or like terms, when used in a historical context (before November 13, 2013), refer to Midcoast Operating. References in this report to Midcoast Energy Partners, the Partnership, MEP, we, our, us, or like terms used in the present tense or prospectively (on and after November 13, 2013) refer to Midcoast Energy Partners, L.P. and its subsidiaries.

Items Affecting the Comparability of Our Financial Results

Our future results of operations may not be comparable to our Predecessor's historical results of operations for the reasons described below:

- Our Predecessor's results of operations historically reflected 100% of the revenues and expenses relating to Midcoast Operating. At the close of the Offering, EEP contributed to us a 39% controlling interest in Midcoast Operating. On July 1, 2014, we acquired from our affiliate, EEP, an additional 12.6% limited partner interest in Midcoast Operating for $350.0 million, which brought our total ownership interest in Midcoast Operating to 51.6%. This transaction represents our first acquisition of additional interests in Midcoast Operating since the Offering. As of September 30, 2014, we consolidated the results of operations of Midcoast Operating and recorded a 48.4% noncontrolling interest for EEP's retained interest in Midcoast Operating.
- Although the allocation methodology under which we continue to reimburse EEP and its affiliates for the provisions of certain administrative and operational services to Midcoast Operating will not change, $25.0 million in annual amounts payable for general and administrative expenses that were paid by Midcoast Operating historically under its existing services agreements will not be payable by Midcoast Operating going forward. For the nine month period ending September 30, 2014, we recognized $18.8 million as a reduction to "Due to general partner and affiliates" with the offset to "Noncontrolling interest" in our consolidated statements of financial position.
- We expect to incur an additional $4.0 million of incremental annual general and administrative expenses as a result of being a separate publicly traded partnership, 100% of which will be attributable to us.
- EEP no longer provides letters of credit and parental guarantees to Midcoast Operating at no cost and we are responsible for our proportionate share of the annual expenses attributable to a financial support agreement that Midcoast Operating entered into with EEP. During the term of the financial support agreement, EEP will provide letters of credit and guarantees in support of Midcoast Operating's financial obligations under certain legacy hedges and key customer natural gas and NGL purchase agreements. The annual cost that Midcoast Operating incurs under the financial support agreement, which we estimate will initially range from approximately $4.0 million to $5.0 million, is based on the cumulative average amount of letters of credit and guarantees that EEP may provide on Midcoast Operating's behalf multiplied by a 2.5% annual fee. Midcoast Operating incurred $2.7 million of these costs for the nine months ended September 30, 2014. EEP has historically provided such financial support to Midcoast Operating at no cost. Without such financial support from EEP, we expect that Midcoast Operating would be required to provide letters of credit, cash collateral or other financial support with respect to these agreements or similar agreements it enters into in the future. For more information regarding our financial support agreement and the calculation of this annual fee, please see "Liquidity and Capital Resources—Financial Support Agreement."
- We incur interest expense under our borrowing arrangements. Prior to our acquiring control of the Predecessor, it was a wholly owned subsidiary of EEP and, as such, did not incur any direct interest expense from third parties and only recognized intercompany interest expense to the extent such amounts were capitalized as part of its construction projects.

RESULTS OF OPERATIONS—OVERVIEW

We are a growth-oriented Delaware limited partnership formed by EEP to serve as EEP's primary vehicle for owning and growing its natural gas and natural gas liquids, or NGL, midstream business in the United States. As of September 30, 2014, we own a 51.6% controlling interest in Midcoast Operating, a Texas limited partnership that owns a network of natural gas and NGL gathering and transportation systems, natural gas processing and treating facilities and NGL fractionation facilities primarily located in Texas and Oklahoma. Midcoast Operating also owns and operates natural gas, condensate and NGL logistics and marketing assets that primarily support its gathering, processing and transportation business. Through our ownership of Midcoast Operating's general partner, we control, manage and operate these systems. On July 1, 2014, we acquired an additional 12.6% ownership interest in Midcoast Operating from EEP for $350.0 million, which reduced the amounts we attribute to noncontrolling interest in our consolidated financial statements.

Our business primarily consists of gathering unprocessed and untreated natural gas from wellhead locations and other receipt points on our systems, processing the natural gas to remove NGLs and impurities at our processing and treating facilities and transporting the processed natural gas and NGLs to and through our intrastate and interstate pipelines for transportation to various customers and market outlets. In addition, we also market natural gas and NGLs to wholesale customers.

Our financial condition and results of operations are subject to variability from multiple factors, including:

- the volumes of natural gas and NGLs that we gather, process and transport on our systems;
- the price of natural gas and NGLs that we pay for and receive in connection with the services we provide;
- our ability to replace or renew existing contracts, such as our ability to replace a significant processing contract on our Anadarko system that terminated during the third quarter of 2013; and
- the supply and demand for natural gas and NGLs.

We conduct our business through two distinct reporting segments: gathering, processing and transportation and logistics and marketing. We have established these reporting segments as strategic business units to facilitate the achievement of our long-term objectives, to aid in resource allocation decisions and to assess operational performance.

The following table reflects our operating income by business segment and corporate charges for each of the three and nine month periods ended September 30, 2014, and 2013.

	For the three month period ended September 30,		For the nine month period ended September 30,	
	2014	2013	2014	2013
	(in millions)			
Operating income (loss)				
Gathering, Processing and Transportation	$19.0	$ 10.7	$14.2	$ 67.2
Logistics and Marketing	(2.3)	(23.6)	11.4	(12.8)
Corporate	(1.5)	—	(3.7)	—
Total operating income (loss)	15.2	(12.9)	21.9	54.4
Interest expense, net	3.6	—	9.7	—
Other income	5.3	—	6.4	0.2
Income tax expense	0.9	0.6	2.7	8.9
Net income (loss)	$16.0	$(13.5)	$15.9	$ 45.7

Contractual arrangements in our Gathering, Processing and Transportation segment and our Logistics and Marketing segment expose us to market risks associated with changes in commodity prices where we receive natural gas or NGLs in return for the services we provide or where we purchase natural gas or NGLs. Our unhedged commodity position is fully exposed to fluctuations in commodity prices, which can be significant during periods of price volatility. We employ derivative financial instruments to hedge a portion of our commodity position and to reduce our exposure to fluctuations in natural gas and NGL prices. Some of these derivative financial instruments do not qualify for hedge accounting under the provisions of authoritative accounting guidance, which can create volatility in our earnings that can be significant. However, these fluctuations in earnings do not affect our cash flow. Cash flow is only affected when we settle the derivative instrument.

Summary Analysis of Operating Results

Gathering, Processing and Transportation

The operating income of our Gathering, Processing and Transportation segment for the three and nine month periods ended September 30, 2014, increased $8.3 million and decreased $53.0 million, respectively, when compared to the same periods in 2013, primarily due to changes in segment gross margin. Operating income is largely derived from segment gross margin, which is operating revenues less cost of natural gas and natural gas liquids. Segment gross margin variances are as follows:

- Segment gross margin increased $15.2 million and decreased $3.6 million for the three and nine month periods ended September 30, 2014, due to non-cash, mark-to-market net gains and net losses from derivative instruments that do not qualify for hedge accounting treatment, when compared to the same period in 2013;
- Segment gross margin increased $2.5 million and $6.9 million for the three and nine month periods ended September 30, 2014, due to contractual minimum volume commitments in which our customer has not moved the required volumes;
- Segment gross margin increased $2.4 million and decreased $1.7 million for the three and nine month periods ended September 30, 2014, respectively, due to increased and decreased margins from pricing differences.
- Segment gross margin decreased approximately $15.0 million and $42.9 million for the three and nine month periods ended September 30, 2014, primarily due to reduced natural gas and NGL average daily volumes on our major systems primarily attributable to the loss of a major customer on our Anadarko system and reduced and delayed drilling activity in the Anadarko and East Texas regions;
- Segment gross margin decreased $7.1 million and $19.0 million for the three and nine month periods ended September 30, 2014, respectively, due to reduced keep-whole processing earnings;
- Segment gross margin decreased approximately $3.0 million for the nine month period ended September 30, 2014, primarily due to the impact of sustained freezing temperatures which significantly disrupted producer well head production levels and our pipeline operations compared to the same periods in 2013;
- Segment gross margin decreased $1.5 million and $3.7 million for the three and nine month periods ended September 30, 2014, respectively due to reduced pricing spreads between the Conway and Mont Belvieu market hubs when compared with the same periods in 2013;
- Operating and maintenance costs decreased $6.1 million and $11.7 million for the three and nine month periods ended September 30, 2014, respectively, as compared to the same periods in 2013 due primarily to decreased outside contract labor, lower rents and leases, and lower pipeline integrity costs; and
- Depreciation and amortization expense increased $1.4 million and $4.1 million for the three and nine month periods ended September 30, 2014, respectively, as compared with the same periods in 2013 due to additional assets that were placed into service.

Logistics and Marketing

The operating income of our Logistics and Marketing segment increased $21.3 million and $24.2 million for the three and nine month periods ended September 30, 2014, respectively, when compared to the same periods in 2013 due to the following:

- Segment gross margin increased due to non-cash, mark-to-market net gains of $37.2 million and $29.0 million for the three and nine month periods ended September 30, 2014, primarily from the non-qualifying commodity derivatives we use to economically hedge a portion of the NGLs and crude oil forward contracts;

- Segment gross margin was relatively flat for the three month period ended September 30, 2014, as compared with the same period in 2013, and increased $10.6 million for the nine month period ended September 30, 2014, as compared with the same period in 2013 due to increased margins from pricing differentials. Higher operating income for the nine month period ended September 30, 2014, was predominantly due to strong natural gas marketing optimization results attributable to seasonal demand for natural gas deliveries from Mid-Continent to the Midwest market. We benefited from the natural gas pricing difference between market centers in the Mid-Continent supply areas and market area in the Midwest, which arose from higher than normal demand from winter weather in the Midwest;
- The increases in segment gross margin were partially offset by a decrease in storage margins of $7.4 million and $12.3 million for the three and nine month periods ended September 30, 2014, respectively, when compared to the same periods in 2013 and by an increase in cost of sales of $4.1 million for the three month period ended September 30, 2014, due to higher transportation and fractionation fees, freight costs, and product purchase costs, when compared to the same period in 2013;
- Operating and administrative expenses decreased $2.0 million and $5.1 million for the three and nine month periods ended September 30, 2014, respectively, when compared to the same periods in 2013, due partly to lower volumes received from our Gathering, Processing and Transportation segment and partly due to a strategic reduction of long hauls due to new geographically advantaged sales points; and
- Depreciation and amortization increased $2.3 million and $2.9 million for the three and nine month periods ended September 30, 2014, respectively, when compared to the same periods in 2013 due to additional assets that were placed into service.

Derivative Transactions and Hedging Activities

We use derivative financial instruments (i.e., futures, forwards, swaps, options and other financial instruments with similar characteristics) to manage the risks associated with market fluctuations in commodity prices, as well as to reduce variability in our cash flows. Based on our risk management policies, all of our derivative financial instruments are employed in connection with an underlying asset, liability and/or forecasted transaction and are not entered into with the objective of speculating on commodity prices. We record all derivative instruments in our consolidated financial statements at fair market value pursuant to the requirements of applicable authoritative accounting guidance. We record changes in the fair value of our derivative financial instruments that do not qualify for hedge accounting in our consolidated statements of income as "Operating revenue" and "Cost of natural gas and natural gas liquids".

The changes in fair value of our derivatives are also presented as a reconciling item on our consolidated statements of cash flows. The following table presents the net changes in fair value associated with our derivative financial instruments:

	For the three month period ended September 30,		For the nine month period ended September 30,	
	2014	2013	2014	2013
	(in millions)			
Gathering, Processing and Transportation segment				
Hedge ineffectiveness	$ 0.9	$ (0.5)	$ 1.5	$ 1.8
Non-qualified hedges	8.7	(5.1)	(1.9)	1.4
Logistics and Marketing segment				
Non-qualified hedges	8.1	(29.1)	11.9	(17.1)
Derivative fair value net gains (losses)	$17.7	$(34.7)	$11.5	$(13.9)

RESULTS OF OPERATIONS—BY SEGMENT

Gathering, Processing and Transportation

The following tables set forth the operating results of our Gathering, Processing and Transportation segment and approximate average daily volumes of natural gas throughput and NGLs produced on our major systems for the periods presented:

	For the three month period ended September 30,		For the nine month period ended September 30,	
	2014	2013	2014	2013
	(in millions)			
Operating revenues	$ 161.4	$ 171.4	$ 534.1	$ 543.0
Cost of natural gas and natural gas liquids	20.7	33.5	155.6	101.7
Segment gross margin	140.7	137.9	378.5	441.3
Operating and maintenance	64.9	71.0	196.5	208.2
General and administrative	21.3	22.1	62.4	64.6
Depreciation and amortization	35.5	34.1	105.4	101.3
Operating expenses	121.7	127.2	364.3	374.1
Operating income	19.0	10.7	14.2	67.2
Other income	5.3	—	6.4	—
Net income	$ 24.3	$ 10.7	$ 20.6	$ 67.2
Operating Statistics (MMBtu/d)				
East Texas	1,063,000	1,120,000	1,021,000	1,201,000
Anadarko	806,000	957,000	816,000	963,000
North Texas	304,000	314,000	292,000	326,000
Total	2,173,000	2,391,000	2,129,000	2,490,000
NGL Production (Bpd)	84,121	88,907	82,578	89,620

Three month period ended September 30, 2014, compared with three month period ended September 30, 2013

The operating income of our Gathering, Processing and Transportation segment for the three month period ended September 30, 2014, increased $8.3 million, as compared with the same period in 2013. The most significant areas affected were segment gross margin and operating and maintenance, which increased $2.8 million and decreased $6.1 million, respectively for the three month period ended September 30, 2014, as compared with the same period in 2013.

Segment gross margin experienced an increase in non-cash, mark-to-market net gains of $15.2 million for the three month period ended September 30, 2014, compared to the same period in 2013 primarily related to increased gains in the three months ended September 30, 2014, on our NGL and condensate hedges and hedge ineffectiveness. We are exposed to fluctuations in commodity prices in the near term on approximately 40% of the physical natural gas, NGLs and condensate we expect to receive as compensation for our services. As a result of this unhedged commodity price exposure, our segment gross margin generally increases when the prices of these commodities are rising and generally decreases when the prices are declining.

Segment gross margin was negatively affected by the reduced production volumes by approximately $15.0 million for the three month period ended September 30, 2014, compared to the same period in 2013. The average daily volumes of our major systems for the three month period ended September 30, 2014, decreased by 218,000 MMBtu/d, or 9%, when compared to the same period in 2013. The average NGL production for the three month period ended September 30, 2014, decreased 4,786 Bpd, or 5%, when compared to the same period in 2013. The decrease in natural gas and NGL volumes in the Anadarko region was primarily attributable to the loss of a major customer on our Anadarko system and reduced and delayed drilling activity by certain producers. The decrease in natural gas volumes in the East Texas region was primarily attributable to reduced dry gas drilling, and delayed drilling activity and well completions.

The natural gas and NGL production volumes have been improving quarter over quarter during the year and the outlook on our systems is expected to improve as we progress through the fourth quarter. We expect producer activity to increase in each of our asset regions with the exception of the Anadarko region. Additionally, drilling activity by natural gas producers in all regions is expected to target rich gas and oil prospects. This is notable in East Texas where existing processing capacity is full. Completion of the Beckville Cryogenic Processing Plant, which is expected to commence service in early 2015, is expected to alleviate this capacity constraint.

Segment gross margin increased by $2.5 million for the three months ended September 30, 2014, from contractual minimum volume commitments that will not be met before the contracts expire.

Segment gross margin increased $2.4 million for the three month period ended September 30, 2014, as compared with the same period in 2013 due to increased margins from pricing differences.

The barrels that we produce under traditional keep-whole gas processing arrangements we refer to collectively as keep-whole earnings. Operating revenue less the cost of natural gas derived from keep-whole earnings for the three month period ended September 30, 2014, decreased $7.1 million from the same period in 2013, primarily due to lower ethane prices in the Anadarko region coupled with lower volumes of propane, butane, and natural gasoline.

Segment gross margin decreased $1.5 million for the three month period ended September 30, 2014, due to reduced pricing spreads between our Conway and Mont Belvieu market hubs when compared with the same period in 2013. On our Anadarko system, we purchase certain NGL components at Conway hub prices and then have the option to resell those same NGL components at Mont Belvieu hub prices.

Operating and maintenance costs decreased $6.1 million for the three month period ended September 30, 2014, compared to the same period in 2013 due primarily to decreased outside contract labor and a reduction in rents and leases.

Depreciation and amortization expense increased $1.4 million for the three month period ended September 30, 2014, compared with the same period of 2013 due to additional assets that were placed into service.

We recognized $6.1 million in equity income in “Other income (expense)” on our consolidated statement of income related to our investment in the Texas Express NGL system, which commenced startup operations during the fourth quarter of 2013.

Nine month period ended September 30, 2014, compared with nine month period ended September 30, 2013

The operating income of our Gathering, Processing and Transportation segment for the nine month period ended September 30, 2014, decreased $53.0 million, as compared with the same period of 2013. The most significant area affected was segment gross margin, which decreased $62.8 million for the nine month period ended September 30, 2014, as compared with the same period in 2013.

Segment gross margin decreased $3.6 million for the nine month period ended September 30, 2014, when compared to the same period in 2013 primarily related to non-cash, mark-to-market losses in the nine months ended September 30, 2014, on our NGL hedges as compared to gains in the same period in 2013.

Segment gross margin was affected by reduced production volumes which negatively affected segment gross margin by approximately $42.9 million for the nine month period ended September 30, 2014, compared to the same period in 2013. The average daily volumes of our major systems for the nine month period ended September 30, 2014, decreased by approximately 361,000 MMBtu/d, or 14%, when compared to the same period in 2013. The average NGL production for the nine month period ended September 30, 2014, decreased by 7,042 Bpd, or 8%, when compared to the same period in 2013. The decrease in natural gas and NGL volumes in the Anadarko region was primarily attributable to the loss of a major customer on our Anadarko system and reduced and delayed drilling activity by certain producers. The decrease in natural gas volumes in the East Texas region was primarily attributable to reduced dry gas drilling, and delayed drilling activity and well completions.

Segment gross margin derived from keep-whole earnings for the nine month period ended September 30, 2014, decreased $19.0 million from the same period in 2013, due to a decrease in processing margins primarily driven by lower volumes in keep-whole barrels in the Oklahoma and North Texas regions.

Segment gross margin decreased $3.7 million for the nine month period ended September 30, 2014, due to reduced pricing spreads between our Conway and Mont Belvieu market hubs when compared with the same period in 2013.

Segment gross margin decreased approximately $3.0 million for the nine month period ended September 30, 2014, primarily due to the impact of sustained freezing temperatures which significantly disrupted producer well head production levels and our pipeline operations compared to the same period in 2013.

Segment gross margin decreased $1.7 million for the nine month period ended September 30, 2014, as compared with the same period in 2013 due to decreased margins from pricing differences.

The decrease in segment gross margin was partially offset by an increase of $6.9 million for the nine months ended September 30, 2014, from contractual cumulative minimum volume commitments that will not be met before the contracts expire.

Operating and maintenance costs decreased $11.7 million for the nine month period ended September 30, 2014, compared to the same period in 2013 primarily related to reduced outside contract labor and lower rents and leases.

Depreciation and amortization expense for our Gathering, Processing and Transportation segment increased $4.1 million, for the nine month period ended September 30, 2014, compared with the same period of 2013 due to additional assets that were placed into service.

We recognized $7.1 million in equity income in “Other income (expense)” on our consolidated statement of income related to our investment in the Texas Express NGL system.

Future Prospects for Gathering, Processing and Transportation

We intend to expand our natural gas gathering and processing services by (1) capturing opportunities within our footprint, (2) expanding outside of our footprint through strategic acquisitions, (3) providing an array of services for both natural gas and natural gas liquids in combination with core asset optimization, and (4) capitalizing on new market opportunities by diversifying geographically and by commodity composition. We will pursue internal growth projects designed to provide exposure to incremental supplies of natural gas at the wellhead, increase opportunities to serve additional customers, including new wholesale customers, and allow expansion of our treating and processing businesses. Additionally, we will pursue acquisitions to expand our natural gas services in situations where we have natural advantages to create additional value.

We have completed several expansion projects and are currently constructing one major expansion project that is designed to increase natural gas processing, NGL production, residue gas and NGL transportation capacity. The paragraph below summarizes our commercially secured project for the Natural Gas segment, which we expect to place into service in future periods.

Beckville Cryogenic Processing Plant

In April 2013, we announced plans to construct a cryogenic natural gas processing plant near Beckville in Panola County, Texas, which we refer to as the Beckville processing plant. This plant is expected to serve existing and prospective customers pursuing production in the Cotton Valley formation as well as the Eaglebine developments. We expect our Beckville processing plant to be capable of processing approximately 150 million cubic feet per day, or MMcf/d, of natural gas and producing approximately 8,500 Bpd of NGLs to accommodate the additional liquids-rich natural gas being developed within this geographical area in which our East Texas system operates. We estimate the cost of constructing the plant to be approximately $145.0 million and expect it to commence service in the first quarter of 2015. The project is funded by the Partnership and EEP based on their proportionate ownership percentages in Midcoast Operating, which was 39% and 61%, respectively, before June 30, 2014, and 51.6% and 48.4%, respectively, after June 30, 2014.

Logistics and Marketing

The following table sets forth the operating results of our Logistics and Marketing segment for the periods presented:

	For the three month period ended September 30,		For the nine month period ended September 30,	
	2014	2013	2014	2013
	(in millions)			
Operating revenues	$1,238.0	$1,209.5	$3,909.0	$3,507.3
Cost of natural gas and natural gas liquids	1,217.5	1,210.8	3,831.1	3,451.7
Segment gross margin	20.5	(1.3)	77.9	55.6
Operating and maintenance	15.7	17.7	49.8	54.9
General and administrative	3.1	2.9	8.8	8.5
Depreciation and amortization	4.0	1.7	7.9	5.0
Operating expenses	22.8	22.3	66.5	68.4
Operating income (loss)	$ (2.3)	$ (23.6)	$ 11.4	$ (12.8)

The primary role of our Logistics and Marketing business is to market natural gas, NGLs and condensate received from our Gathering, Processing and Transportation business. We purchase and receive natural gas, NGLs and other products from pipeline systems and processing plants and sell and deliver them to wholesale customers, such as distributors, refiners, fractionators, utilities, chemical facilities and power plants. Our Logistics and Marketing segment derives a majority of its operating income from selling natural gas, NGLs, and condensate received from producers on our Gathering, Processing and Transportation segment pipeline assets. A majority of the natural gas and NGLs we purchase are produced in Texas markets where we have expanded access to several interstate natural gas pipelines over the past several years. We can use those interstate pipelines to transport natural gas and NGLs to primary markets where we can sell them to major customers. Additionally, our Logistics and Marketing segment derives operating income from providing logistics services for our customers from the wellhead to markets.

Generally, the demand for natural gas and NGLs is higher during the winter months as these commodities are used to meet residential and commercial heating requirements. In some areas during the summer months, demand for natural gas is higher as utility companies that use natural gas for power generation increase their electricity output to meet residential and commercial demand for air conditioning. Seasonal anomalies such as mild winters or hot summers can lessen or intensify these fluctuations.

Three month period ended September 30, 2014, compared with three month period ended September 30, 2013

The operating income of our Logistics and Marketing segment for the three month period ended September 30, 2014, increased $21.3 million, as compared with the same period in 2013. The most significant area affected was segment gross margin which increased $21.8 million for the three month period ended September 30, 2014, as compared with the same period in 2013.

Segment gross margin experienced an increase in non-cash, mark-to-market net gains of $37.2 million for the three month period ended September 30, 2014, compared to the same period in 2013 primarily from gains due to the NGL and crude oil forward contracts and the non-qualifying commodity derivatives we use to economically hedge a portion of the NGLs resulting from the operating activities of our Logistics and Marketing segment.

Our segment gross margin decreased $7.4 million for the three month period ended September 30, 2014, compared with the same period in 2013 in our Logistics and Marketing segment due in part to lower storage margins as a result of lower volumes received from our Gathering, Processing and Transportation segment.

Our segment gross margin decreased $4.1 million for the three month period ended September 30, 2014, compared with the same period in 2013 due to higher transportation and fractionation fees, freight costs, and product purchase costs, when compared to the same period in 2013.

Operating and administrative costs of our Logistics and Marketing segment were $2.0 million lower for the three month period ended September 30, 2014, compared with the three month period ended September 30, 2013, due partly to lower volumes received from our Gathering, Processing and Transportation segment and partly due to a strategic reduction of long hauls due to new geographically advantaged sales points.

Depreciation and amortization expense for the three month period ended September 30, 2014, increased $2.3 million for the three month period ended September 30, 2014, when compared with the same period ended September 30, 2013, due to additional assets that were placed into service.

Nine month period ended September 30, 2014, compared with nine month period ended September 30, 2013

The operating income of our Logistics and Marketing segment for the nine month period ended September 30, 2014, increased $24.2 million, as compared with the same period in 2013.

Segment gross margin experienced an increase in non-cash, mark-to-market net gains of $29.0 million for the nine month period ended September 30, 2014, compared to the same period in 2013 primarily from gains due to the NGL and crude oil forward contracts and the non-qualifying commodity derivatives we use to economically hedge a portion of the NGLs resulting from the operating activities of our Logistics and Marketing segment.

Segment gross margin increased $10.6 million for the nine month period ended September 30, 2014, as compared with the same period in 2013 due to increased margins from pricing differentials. We benefited from the difference between market centers in the Mid-Continent supply areas and market area in the Midwest, which arose from higher than normal demand from winter weather in the Midwest.

The increase in our segment gross margin was partially offset by a decrease of $12.3 million for the nine month period ended September 30, 2014, compared with the same period in 2013, due in part to lower storage volumes as a result of lower volumes received from our Gathering, Processing and Transportation segment.

Operating and administrative costs decreased $5.1 million for the nine month period ended September 30, 2014, as compared with the same period in 2013, due partly to lower volumes received from our Gathering, Processing and Transportation segment and partly due to a strategic reduction of long hauls due to new geographically advantaged sales points.

Depreciation and amortization expense for the nine month period ended September 30, 2014, increased $2.9 million for nine month period ended September 30, 2014, as compared with the same period in 2013, due to additional assets that were placed into service.

Corporate

Our corporate activities consist of interest expense, interest income and other costs such as income taxes, which are not allocated to the business segments.

	For the three month period ended September 30,		For the nine month period ended September 30,	
	2014	2013	2014	2013
	(in millions)			
Operating and maintenance	$ —	$—	$ 0.2	$—
General and administrative	1.5	—	3.5	—
Operating expenses	1.5	—	3.7	—
Operating loss	(1.5)	—	(3.7)	—
Interest expense, net	3.6	—	9.7	—
Other income	—	—	—	0.2
Income tax expense	0.9	0.6	2.7	8.9
Net loss	(6.0)	(0.6)	(16.1)	(8.7)
Net income attributable to noncontrolling interests	9.7	—	13.8	—
Net loss attributable to general and limited partners	$(15.7)	$(0.6)	$(29.9)	$(8.7)

Three month period ended September 30, 2014, compared with three month period ended September 30, 2013

General and administrative expenses increased $1.5 million for the three month period ended September 30, 2014, as compared to the same period in 2013 due to increased professional fees and costs incurred since our initial public offering.

Interest expense increased $3.6 million for the three month period ended September 30, 2014, as compared to the same period in 2013. We did not have any outstanding debt at September 30, 2013.

We are not a taxable entity for United States federal income tax purposes or for the majority of states that impose an income tax. Taxes on our net income are typically borne by our unitholders through the allocation of taxable income.

The tax structure that exists in Texas imposes taxes that are based upon many, but not all, items included in net income. Our income tax expense of $0.9 million and $0.6 million for the three month periods ended September 30, 2014, and September 30, 2013, respectively, is computed by applying a 0.5% Texas state income tax rate to modified gross margin, as defined by Texas state income tax laws.

Nine month period ended September 30, 2014, compared with nine month period ended September 30, 2013

General and administrative expenses increased $3.5 million for the nine month period ended September 30, 2014, as compared to the same period in 2013 due to increased professional fees and costs incurred since our initial public offering.

Interest expense increased $9.7 million for the nine month period ended September 30, 2014, as compared to the same period in 2013. We did not have any outstanding debt at September 30, 2013.

Income tax expense decreased $6.2 million for the nine month period ended September 30, 2014, compared to the same period in 2013, primarily due to a tax law that was passed in 2013 in the State of Texas, which resulted in a one-time increase to deferred income tax expense.

LIQUIDITY AND CAPITAL RESOURCES

Historically, our sources of liquidity included cash generated from operations and funding from EEP. We were dependent upon EEP and its affiliates for our treasury services. We now have separate bank accounts from EEP, but EEP and its affiliates provide treasury services on our General Partner's behalf under an intercorporate services agreement that we entered into with EEP at the closing of the Offering. Under the intercorporate services agreement, EEP has agreed to reduce the amounts payable for general and administrative expenses that otherwise would be fully allocable to Midcoast Operating by $25.0 million annually.

At the close of the Offering, Midcoast Operating entered into a Financial Support Agreement, which we refer to as the Financial Support Agreement, between Midcoast Operating and EEP, pursuant to which EEP will, from time to time, provide letters of credit and guarantees, not to exceed $700.0 million in the aggregate at any time outstanding, in support of Midcoast Operating's and its wholly owned subsidiaries' financial obligations under derivative agreements and natural gas and NGL purchase agreements to which Midcoast Operating, or one or more of its wholly owned subsidiaries, is a party.

We expect our ongoing sources of liquidity to include cash generated from operations of Midcoast Operating, borrowings under Midcoast Operating's working capital credit facility, borrowings under our senior revolving credit facility, which we refer to as the Credit Agreement, and issuances of additional debt and equity securities. We believe that cash generated from these sources will be sufficient to meet our short-term working capital requirements and long-term capital expenditure requirements and to make quarterly cash distributions to our unitholders.

On July 1, 2014, we acquired an additional 12.6% limited partner interest in Midcoast Operating from EEP for $350.0 million, which brought our total ownership interest in Midcoast Operating to 51.6%. This transaction represents our first acquisition of additional interests in Midcoast Operating since the Offering. We do not know when, or if, any additional interests will be offered to us to purchase. As a result of our increased ownership interest in Midcoast Operating, we will have increased funding requirements for capital projects in periods subsequent to the drop down transaction.

Available Liquidity

Our primary source of liquidity is provided by the Credit Agreement. On October 30, 2014, the board of directors of Midcoast Holdings, acting in its capacity as the General Partner of MEP, on behalf of Midcoast OLP GP, L.L.C., acting in its capacity as the general partner of Midcoast Operating, approved the termination of our $250.0 million working capital credit facility with EEP as the lender. Midcoast Operating has exercised its right under the working capital facility to terminate the agreement upon 30-days' notice, and such termination is expected to occur in the fourth quarter. At the time of the termination, there is not expected to be any outstanding borrowings under this facility.

As set forth in the following table, at September 30, 2014, we had $551.2 million of liquidity available to us, excluding the working capital credit facility, to meet our ongoing operational, investment and financing needs.

	(in millions)
Cash and cash equivalents	$ 66.2
Total credit available under Credit Agreement	850.0
Amounts outstanding under Credit Agreement	(365.0)
Total	$ 551.2

At September 30, 2014, we had available approximately $485.0 million under the terms of our Credit Agreement.

Credit Agreement

On November 13, 2013, we, Midcoast Operating, and our material domestic subsidiaries, entered into the Credit Agreement, which permits aggregate borrowings of up to, at any one time outstanding, $850.0 million. The original term of the Credit Agreement is three years, with an initial maturity date of November 13, 2016, subject to four one-year requests for extensions. On September 30, 2014, we amended our Credit Agreement to extend the maturity date from November 13, 2016, to September 30, 2017; however, $140.0 million of commitments will expire on the original maturity date of November 13, 2016. In connection with the amendment to our Credit Agreement, we entered into an amended and restated subordination agreement by and among us, Midcoast Operating, the other parties from time to time party thereto and EEP in favor of Bank of America, N.A., as administrative agent, and for the benefit of the administrative agent and the lenders party to the Credit Agreement, to accommodate the subordination agreement entered into in connection with the Purchase Agreement, described under "Private Debt Issuance."

At September 30, 2014, we had $365.0 million in outstanding borrowings under the Credit Agreement at a weighted average interest rate of 1.9%. Under the Credit Agreement, we had net borrowings of approximately $30.0 million during the nine month period ended September 30, 2014, which includes gross borrowings of $5,570.0 million and gross repayments of $5,540.0 million. At September 30, 2014, we were in compliance with the terms of our financial covenants in the Credit Agreement.

Private Debt Issuance

On September 30, 2014, we completed a private debt issuance of $400.0 million. The debt consists of three tranches of senior notes: $75.0 million of 3.56% Series A Senior Notes due in 2019; $175.0 million of 4.04% Series B Senior Notes due in 2021; and $150.0 million of 4.42% Series C Senior Notes due in 2024, collectively the Notes. All of the Notes pay interest semi-annually on March 31 and September 30, commencing on March 31, 2015. We received approximately $398.1 million in net proceeds, which were used to repay outstanding indebtedness and for other general partnership purposes. Using a portion of the net proceeds, we settled two interest rate swaps for a net payment of $0.9 million on September 30, 2014, which will be amortized to interest expense over the original 5 year hedge term.

Cash Requirements

Capital Spending

We categorize our capital expenditures as either maintenance capital or expansion capital expenditures. Maintenance capital expenditures are those expenditures that are necessary to maintain the service capability of our existing assets and include the replacement of system components and equipment which are worn, obsolete or completing its useful life. Examples of maintenance capital expenditures include expenditures to replace pipelines or processing facilities, to maintain equipment reliability, integrity and safety or to comply with existing governmental regulations and industry standards. We also include in maintenance capital expenditures a portion of our expenditures for connecting natural gas wells, or well-connects, to our natural gas gathering systems.

Expansion capital expenditures include our capital expansion projects and other projects that improve the service capability of our existing assets, extend asset useful lives, increase capacities from existing levels, reduce costs or enhance revenues and enable us to respond to governmental regulations and developing industry standards. Examples of expansion capital expenditures include the acquisition of additional assets or businesses, as well as capital projects that improve the service, integrity and safety capability of our existing assets, increase operating capacities or revenues, reduce operating costs from existing levels, or enable us to comply with new governmental regulations or industry standards.

If EEP elects not to fund any capital expenditures at Midcoast Operating, we will have the option to fund all or a portion of EEP's proportionate share of such capital expenditures in exchange for additional interests in Midcoast Operating. As a result, if our interests in Midcoast Operating increase, our proportionate share of the capital expenditures incurred by Midcoast Operating will also increase proportionate to our interest in Midcoast Operating. To the extent that EEP elects not to fund all or a portion of its proportionate share of Midcoast Operating's capital expenditures, and we elect not to fund any capital expenditures not funded by EEP, we expect that Midcoast Operating will not pursue the applicable capital projects associated with such unfunded capital expenditures.

At September 30, 2014, we had approximately $59.7 million in outstanding purchase commitments attributable to capital projects for the construction of assets that will be recorded as property, plant and equipment during 2014. The following table sets forth our estimated maintenance and expansion capital expenditures of $125.0 million for the year ending December 31, 2014. Although we anticipate making these expenditures in 2014, these estimates may change due to factors beyond our control, including weather-related issues, construction timing, changes in supplier prices or poor economic conditions, which may adversely affect our ability to access the capital markets. Additionally, our estimates may also change as a result of decisions made at a later date to revise the scope of a project or undertake a particular capital program or an acquisition of assets. As of September 30, 2014, we have incurred approximately $161.6 million in capital expenditures, including $41.3 million on maintenance capital activities. We also incurred $24.6 million in net contributions to fund our joint ventures. For the year ending December 31, 2014, we anticipate our capital expenditures to approximate the following:

	Total Forecasted Expenditures
	(in millions)
Capital Projects	
Beckville Cryogenic Processing Plant	$105
Wellconnect Expansion Capital	20
Texas Express NGL system	25
Expansion Capital [(1)]	65
Maintenance Capital Expenditure Activities	55
Less joint funding from:	
EEP [(2)]	145
	$125

(1) Includes new compression, growth opportunities as well as other enhancements.

(2) Joint funding is based upon six months of EEP at a 61% ownership of Midcoast Operating and six months of EEP at a 48.4% ownership of Midcoast Operating.

Other Purchase Commitments

At September 30, 2014, we had approximately $40.7 million in outstanding purchase commitments attributable to commodity purchases.

Derivative Activities

We use derivative financial instruments (i.e., futures, forwards, swaps, options and other financial instruments with similar characteristics) to manage the risks associated with market fluctuations in commodity prices, as well as to reduce the volatility in our cash flows. Based on our risk management policies, all of our derivative financial instruments are employed in connection with an underlying asset, liability and/or forecasted transaction and are not entered into with the objective of speculating on commodity prices.

The following table provides summarized information about the timing and expected settlement amounts of our outstanding commodity derivative financial instruments based upon the market values at September 30, 2014, for each of the indicated calendar years:

	Notional	2014	2015	2016	2017	2018	Total [3]
			(in millions)				
Swaps							
Natural gas [1]	78,671,325	$ 0.6	$(0.6)	$(0.2)	$—	$—	$ (0.2)
NGL [2]	3,814,740	1.5	1.3	—	—	—	2.8
Crude Oil [2]	1,805,810	0.5	2.6	0.1	—	—	3.2
Options							
Natural gas—puts purchased [1]	6,766,000	0.1	1.4	0.5	—	—	2.0
Natural gas—puts written [1]	5,119,000	(0.1)	(1.4)	—	—	—	(1.5)
Natural gas—calls written [1]	2,924,500	—	(0.1)	(0.3)	—	—	(0.4)
Natural gas—calls purchased [1]	1,277,500	—	0.1	—	—	—	0.1
NGL—puts purchased [2]	2,824,700	0.9	5.5	6.5	—	—	12.9
NGL—calls purchased [2]	46,000	—	—	—	—	—	—
NGL—calls written [2]	1,925,250	(0.1)	(1.7)	(5.6)	—	—	(7.4)
NGL—puts written [2]	32,200	(0.5)	—	—	—	—	(0.5)
Crude Oil—puts purchased [2]	986,700	—	2.3	2.0	—	—	4.3
Crude Oil—calls written [2]	986,700	—	(2.1)	(2.2)	—	—	(4.3)
Forward contracts							
Natural gas [1]	230,964,144	0.6	0.7	0.3	0.1	—	1.7
NGL [2]	18,778,407	6.0	1.5	—	—	—	7.5
Crude Oil [2]	1,029,914	(1.6)	0.2	—	—	—	(1.4)
Totals		$ 7.9	$ 9.7	$ 1.1	$ 0.1	$—	$18.8

(1) Notional amounts for natural gas are recorded in Millions of British Thermal Units, or MMBtu.

(2) Notional amounts for NGLs and crude oil are recorded in Barrels, or Bbl.

(3) Fair values are presented in millions of dollars and exclude credit valuation adjustments of approximately $0.1 million of losses at September 30, 2014.

Cash Flow Analysis

The following table summarizes the changes in cash flows by operating, investing and financing for each of the periods indicated:

	For the nine month period ended September 30, 2014	2013	Variance 2014 vs. 2013 Increase (Decrease)
	(in millions)		
Total cash provided by (used in):			
Operating activities	$ 112.0	$ 425.9	$(313.9)
Investing activities	(120.2)	(386.5)	266.3
Financing activities	69.5	(39.4)	108.9
Net increase in cash and cash equivalents	61.3	—	61.3
Cash and cash equivalents at beginning of year	4.9	—	4.9
Cash and cash equivalents at end of period	$ 66.2	$ —	$ 66.2

Operating Activities

Net cash provided by our operating activities decreased $313.9 million for the nine month period ended September 30, 2014, compared to the same period in 2013, primarily due to a $260.6 million decrease in our working capital accounts. This decrease is coupled with a $29.8 million decrease in net income and increased derivative net gains of $25.4 million as a result of fluctuations in commodity prices and volumes.

Changes in our working capital accounts are shown in the following table and discussed below:

	For the nine month period ended September 30, 2014	2013	Variance 2014 vs. 2013
	(in millions)		
Changes in operating assets and liabilities, net of acquisitions:			
Receivables, trade and other	$ 11.5	$ (28.8)	$ 40.3
Due from General Partner and affiliates	641.7	10.6	631.1
Accrued receivables	28.0	463.2	(435.2)
Inventory	(129.1)	(75.1)	(54.0)
Current and long-term other assets	(11.5)	(7.0)	(4.5)
Due to General Partner and affiliates	(487.4)	(1.9)	(485.5)
Accounts payable and other	(50.6)	(23.2)	(27.4)
Environmental liabilities	0.2	—	0.2
Accrued purchases	(21.3)	(97.5)	76.2
Interest payable	0.4	—	0.4
Property and other taxes payable	6.6	8.8	(2.2)
Net change in working capital accounts	$ (11.5)	$249.1	$(260.6)

The changes in our operating assets and liabilities, net of acquisitions as presented in our consolidated statements of cash flow for the nine month period ended September 30, 2014, compared to the same period in 2013, is primarily the result of general timing differences for cash receipts and payments associated with current accounts. Other items affecting our cash flows from operating assets and liabilities include the following:

- The changes in the balances due to and due from General Partner and affiliates are primarily attributable to transition of cash management functions from EEP to MEP following the Offering at the end of 2013. EEP provided us with interim cash management services following the Offering to facilitate the collection of and payment on our accounts, which resulted in increase in amounts receivable from and payable to EEP as of December 31, 2013. During the nine month period ended September 30, 2014, we completed this transition and settled most of the transactions causing a decrease in both our due to and due from General Partner and affiliates account. These transactions were not present during the nine month period ended September 30, 2013;

- The decrease in accrued receivables of $463.2 million from December 31, 2012, to September 30, 2013 was primarily the result of having sold $308.7 million of our accrued receivables outstanding as of December 31, 2012 to an Enbridge subsidiary under a purchase agreement, or the Receivables Agreement, that we entered into on June 28, 2013. In addition, we had decreased volumes on our systems due to decreased drilling activity. For the nine month period ended September 30, 2014, our sales decreased even more than the nine month period ended September 30, 2013 due to continued reduced volumes;
- The decline in accrued purchases from December 31, 2012, to September 30, 2013 was primarily the result of lower volumes as a result of decreased drilling activity. During the nine month period ended September 30, 2014, we purchased more butane for our growing business selling to refiners and more propane to meet the additional estimated demand based on the prior year's shortage; and
- Inventory balances at September 30, 2014 and September 30, 2013 were higher than at December 31, 2013 and December 31, 2012, respectively, resulting in a decrease to cash flow from operating activities. The higher balances of inventory are mainly attributable to seasonal build in inventory levels within our Logistics and Marketing segment at lower prices during the summer months relative to the fall and winter months when demand for these products is typically higher due to colder weather conditions. For the nine month period ended September 30, 2014, we increased our inventory of butane and propane due to the same reasons as described in the bullet variance explanation above for "accrued purchases".

Investing Activities

Net cash used in our investing activities during the nine month period ended September 30, 2014, decreased by $266.3 million, compared to the same period in 2013, primarily due to:

- Decreased contributions to fund the construction activities associated with the Texas Express NGL system of approximately $146.4 million since the system went into service in late 2013, coupled with $27.0 million in distributions in excess of cumulative earnings from our joint venture investment in the Texas Express NGL system received during the nine month period ended September 30, 2014;
- Decreased restricted cash balance of $55.6 million in September 2014 consisting of cash collections related to the receivables sold that have yet to be remitted to the Enbridge subsidiary in accordance with the Receivables Agreement; and
- Decreased additions to property, plant and equipment, net of construction payables of $40.0 million when compared with 2013, due to many of our capital projects being put into service in 2013 with less capital projects projected for the future.

Financing Activities

Net cash provided by our financing activities increased $108.9 million for the nine month period ended September 30, 2014, compared to the same period in 2013, due to:

- Increased proceeds of $398.1 million from the issuance of debt through the private placement of three series of senior notes coupled with increased net borrowings of $30.0 million for amounts previously outstanding under our credit facility in 2014, while we had no debt activity during 2013;
- Distributions to partners of $37.1 million for the nine month period ended September 30, 2014 compared to no distributions to partners during the same period in 2013, which was before the Offering;

- Decreased distributions to Predecessor partner interests of $206.3 million during the nine month period ended September 30, 2013, compared to no distributions during the same period in 2014, which was after the Offering. Such distributions were offset by a payment of $350.0 million to EEP for our acquisition of a portion of its noncontrolling interest in MOLP in 2014; and
- Decreased contributions from noncontrolling interest and partners of $55.1 million coupled with increased distributions to noncontrolling interest of $83.3 million.

SUBSEQUENT EVENTS

Termination of Working Capital Credit Facility

On October 30, 2014, the board of directors of Midcoast Holdings, acting in its capacity as the General Partner of MEP, on behalf of Midcoast OLP GP, L.L.C., acting in its capacity as the general partner of Midcoast Operating approved the termination of the working capital credit facility with EEP as the lender. Midcoast Operating has exercised its right under the working capital facility to terminate the agreement upon 30-days' notice, and such termination is expected to occur in the fourth quarter. At the time of the termination, there is not expected to be any outstanding borrowings under this facility.

Distribution to Partners

On October 30, 2014, the board of directors of Midcoast Holdings, acting in its capacity as the General Partner of MEP, declared a cash distribution payable to our partners on November 14, 2014. The distribution will be paid to unitholders of record as of November 7, 2014, of our available cash of $15.6 million at September 30, 2014, or $0.3375 per limited partner unit. We will pay $7.2 million to our public Class A common unitholders, while $8.4 million in the aggregate will be paid to EEP with respect to its Class A common units and subordinated units and Midcoast Holdings, L.L.C., with respect to its general partner interest.

Midcoast Operating Distribution

On October 30, 2014, the general partner of Midcoast Operating, acting in its capacity as the General Partner of Midcoast Operating, declared a cash distribution by Midcoast Operating payable to its partners of record as of November 7, 2014. Midcoast Operating will pay $13.5 million to us and $12.6 million to EEP.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

The following should be read in conjunction with the information presented in our Annual Report on 10-K for the fiscal year ended December 31, 2013, filed on February 18, 2014, in addition to information presented in Items 1 and 2 of this Quarterly Report on Form 10-Q. There have been no material changes to that information other than as presented below.

Our net income and cash flows are subject to volatility stemming from fluctuations in commodity prices of natural gas, NGLs, condensate and fractionation margins. Fractionation margins represent the relative difference between the price we receive from NGL and condensate sales and the corresponding cost of natural gas we purchase for processing. Our exposure to commodity price risk exists within both of our segments. We use derivative financial instruments (i.e., futures, forwards, swaps, options and other financial instruments with similar characteristics) to manage the risks associated with market fluctuations in commodity prices, as well as to reduce the volatility in our cash flows. Based on our risk management policies, all of our derivative financial instruments are employed in connection with an underlying asset, liability and/or forecasted transaction and are not entered into with the objective of speculating on commodity prices.

Fair Value Measurements of Commodity Derivatives

The following table provides summarized information about the fair values of expected cash flows of our outstanding commodity based swaps and physical contracts at September 30, 2014, and December 31, 2013.

	At September 30, 2014						At December 31, 2013	
			Wtd. Average Price (2)		Fair Value (3)		Fair Value (3)	
	Commodity	Notional (1)	Receive	Pay	Asset	Liability	Asset	Liability
					(in millions)			
Portion of contracts maturing in 2014								
Swaps								
Receive variable/pay fixed	Natural Gas	668,692	$ 4.00	$ 3.91	$ 0.1	$—	$—	$ —
	NGL	623,000	$56.02	$56.64	$ 0.3	$(0.7)	$ 0.6	$ (0.4)
	Crude Oil	95,000	$89.87	$92.56	$—	$(0.3)	$—	$ —
Receive fixed/pay variable	Natural Gas	2,380,100	$ 4.26	$ 4.09	$ 0.5	$(0.1)	$ 0.1	$ (1.0)
	NGL	2,021,140	$51.91	$50.97	$ 3.7	$(1.8)	$ 4.8	$(12.7)
	Crude Oil	330,160	$92.67	$90.11	$ 1.2	$(0.4)	$ 0.3	$ (5.4)
Receive variable/pay variable	Natural Gas	19,562,500	$ 4.03	$ 4.02	$ 0.6	$(0.5)	$ 0.6	$ (0.1)
Physical Contracts								
Receive variable/pay fixed	Natural Gas	313,224	$ 3.89	$ 1.23	$ 0.8	$—	$—	$ —
	NGL	550,000	$42.40	$43.88	$—	$(0.8)	$ 0.9	$ (0.9)
	Crude Oil	45,000	$90.85	$93.90	$—	$(0.1)	$—	$ —
Receive fixed/pay variable	Natural Gas	185,506	$ 4.03	$ 3.97	$—	$—	$—	$ —
	NGL	3,504,872	$39.20	$37.85	$ 5.1	$(0.4)	$ 0.4	$ (2.6)
	Crude Oil	75,000	$93.08	$90.62	$ 0.2	$—	$—	$ (0.4)
Receive variable/pay variable	Natural Gas	72,613,470	$ 4.02	$ 4.02	$ 0.9	$(1.1)	$ 0.9	$ (0.4)
	NGL	10,947,422	$42.80	$42.61	$ 2.7	$(0.6)	$ 5.8	$ (3.7)
	Crude Oil	758,914	$88.26	$90.52	$ 0.8	$(2.5)	$ 1.1	$ (1.2)
Portion of contracts maturing in 2015								
Swaps								
Receive variable/pay fixed	Natural Gas	316,837	$ 3.91	$ 3.93	$—	$—	$—	$ —
	NGL	145,850	$72.56	$78.20	$—	$(0.8)	$—	$ —
	Crude Oil	456,000	$87.81	$92.94	$—	$(2.3)	$—	$ —
Receive fixed/pay variable	Natural Gas	809,761	$ 4.56	$ 4.21	$ 0.3	$—	$—	$ —
	NGL	1,024,750	$54.42	$52.36	$ 3.1	$(1.0)	$ 1.5	$ (1.1)
	Crude Oil	788,150	$94.02	$87.79	$ 4.9	$—	$ 1.7	$ —
Receive variable/pay variable	Natural Gas	42,725,000	$ 3.92	$ 3.94	$ 0.8	$(1.7)	$ 0.1	$ —
Physical Contracts								
Receive variable/pay fixed	NGL	95,000	$46.73	$48.37	$—	$(0.2)	$—	$ —
Receive fixed/pay variable	NGL	586,394	$49.38	$47.79	$ 1.0	$—	$—	$ —
Receive variable/pay variable	Natural Gas	108,991,322	$ 4.05	$ 4.05	$ 1.4	$(0.7)	$ 0.5	$ (0.1)
	NGL	3,094,719	$61.40	$61.19	$ 1.2	$(0.5)	$—	$ —
	Crude Oil	151,000	$90.30	$88.89	$ 0.2	$—	$—	$ —
Portion of contracts maturing in 2016								
Swaps								
Receive fixed/pay variable	Crude Oil	68,250	$90.89	$86.36	$ 0.3	$—	$ 0.7	$ —
Receive variable/pay fixed	Crude Oil	68,250	$86.36	$90.00	$—	$(0.2)	$—	$ —
	Natural Gas	181,435	$ 3.78	$ 3.85	$—	$—	$—	$ —
Receive variable/pay variable	Natural Gas	12,027,000	$ 3.96	$ 3.98	$ 0.1	$(0.3)	$—	$ —
Physical Contracts								
Receive variable/pay variable	Natural Gas	34,560,879	$ 4.06	$ 4.05	$ 0.7	$(0.4)	$ 0.1	$ —
Portion of contracts maturing in 2017								
Physical Contracts								
Receive variable/pay variable	Natural Gas	14,299,743	$ 4.27	$ 4.26	$ 0.2	$(0.1)	$—	$ —

(1) Volumes of natural gas are measured in MMBtu, whereas volumes of NGL and crude oil are measured in Bbl.

(2) Weighted average prices received and paid are in $/MMBtu for natural gas and $/Bbl for NGL and crude oil.

(3) The fair value is determined based on quoted market prices at September 30, 2014, and December 31, 2013, respectively, discounted using the swap rate for the respective periods to consider the time value of money. Fair values are presented in millions of dollars and exclude credit valuation adjustments of approximately $0.1 million of losses at September 30, 2014 and $0.1 million of gains at December 31, 2013.

The following table provides summarized information about the fair values of expected cash flows of our outstanding commodity options at September 30, 2014, and December 31, 2013.

	At September 30, 2014						At December 31, 2013	
					Fair Value [3]		Fair Value [3]	
	Commodity	Notional [1]	Strike Price [2]	Market Price [2]	Asset	Liability	Asset	Liability
					(in millions)			
Portion of option contracts maturing in 2014								
Puts (purchased) . . .	Natural Gas	1,104,000	$ 3.90	$ 4.10	$ 0.1	$—	$ 0.7	$—
	NGL	193,200	$54.79	$52.43	$ 0.9	$—	$ 2.9	$—
Calls (written)	NGL	115,000	$60.92	$54.59	$—	$(0.1)	$—	$(1.0)
Puts (written)	Natural Gas	1,104,000	$ 3.90	$ 4.10	$—	$(0.1)	$—	$(0.5)
	NGL	32,200	$66.36	$51.70	$—	$(0.5)	$—	$—
Calls (purchased) . .	NGL	46,000	$50.40	$43.84	$—	$—	$—	$—
Portion of option contracts maturing in 2015								
Puts (purchased) . . .	Natural Gas	4,015,000	$ 3.90	$ 4.00	$ 1.4	$—	$ 1.7	$—
	NGL	1,350,500	$48.75	$50.62	$ 5.5	$—	$ 6.0	$—
	Crude Oil	547,500	$85.42	$87.76	$ 2.3	$—	$ 1.8	$—
Calls (written)	Natural Gas	1,277,500	$ 5.05	$ 4.00	$—	$(0.1)	$—	$(0.3)
	NGL	529,250	$55.18	$50.29	$—	$(1.7)	$—	$(1.0)
	Crude Oil	547,500	$91.75	$87.76	$—	$(2.1)	$—	$(1.9)
Puts (written)	Natural Gas	4,015,000	$ 3.90	$ 4.00	$—	$(1.4)	$—	$—
Calls (purchased) . .	Natural Gas	1,277,500	$ 5.05	$ 4.00	$ 0.1	$—	$—	$—
Portion of option contracts maturing in 2016								
Puts (purchased) . . .	Natural Gas	1,647,000	$ 3.75	$ 4.08	$ 0.5	$—	$—	$—
	NGL	1,281,000	$41.82	$44.06	$ 6.5	$—	$—	$—
	Crude Oil	439,200	$80.00	$85.93	$ 2.0	$—	$—	$—
Calls (written)	Natural Gas	1,647,000	$ 4.98	$ 4.08	$—	$(0.3)	$—	$—
	NGL	1,281,000	$48.59	$44.06	$—	$(5.6)	$—	$—
	Crude Oil	439,200	$92.25	$85.93	$—	$(2.2)	$—	$—

(1) Volumes of natural gas are measured in MMBtu, whereas volumes of NGL and crude oil are measured in Bbl.

(2) Strike and market prices are in $/MMBtu for natural gas and in $/Bbl for NGL and crude oil.

(3) The fair value is determined based on quoted market prices at September 30, 2014, and December 31, 2013, respectively, discounted using the swap rate for the respective periods to consider the time value of money. Fair values are presented in millions of dollars and exclude any credit valuation adjustments at September 30, 2014.

Our credit exposure for OTC derivatives is directly with our counterparty and continues until the maturity or termination of the contract. When appropriate, valuations are adjusted for various factors such as credit and liquidity considerations.

	September 30, 2014	December 31, 2013
	(in millions)	
Counterparty Credit Quality [1]		
AAA	$ 0.3	$ 0.2
AA	2.3	(2.1)
A	10.5	(1.1)
Lower than A	5.6	1.6
	$18.7	$(1.4)

(1) As determined by nationally-recognized statistical ratings organizations.

Item 4. Controls and Procedures

We, EEP and Enbridge maintain systems of disclosure controls and procedures designed to provide reasonable assurance that we are able to record, process, summarize and report the information required to be disclosed in the reports that we file or submit under the Securities Exchange Act of 1934, as amended, or the Exchange Act, within the time periods specified in the rules and forms of the SEC, and that such information is accumulated and communicated to our management, including our principal executive and principal financial officers, as appropriate, to allow timely decisions regarding required disclosure. Our management, with the participation of our principal executive and principal financial officers, has evaluated the effectiveness of our disclosure controls and procedures as of September 30, 2014. Based upon that evaluation, our principal executive and principal financial officers concluded that our disclosure controls and procedures are effective at the reasonable assurance level. In conducting this assessment, our management relied on similar evaluations conducted by employees of Enbridge affiliates who provide certain treasury, accounting and other services on our behalf.

There have been no changes in internal control over financial reporting that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting during the three month period ended September 30, 2014.

PART II—OTHER INFORMATION

Item 1. Legal Proceedings

Refer to Part I, Item 1. *Financial Statements*, "Note 10. *Commitments and Contingencies*," which is incorporated herein by reference.

Item 1A. Risk Factors

There have been no material changes to the risk factors previously disclosed in our Annual Report on Form 10-K for the fiscal year ended December 31, 2013, filed with the SEC on February 18, 2014.

Item 6. Exhibits

Reference is made to the "Index of Exhibits" following the signature page, which we hereby incorporate into this Item.

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.

MIDCOAST ENERGY PARTNERS, L.P.
(Registrant)

By: Midcoast Holdings, L.L.C.
as General Partner

Date: November 3, 2014

By: /s/ C. Gregory Harper

C. Gregory Harper
Principal Executive Officer

Date: November 3, 2014

By: /s/ Stephen J. Neyland

Stephen J. Neyland
Vice President—Finance
(Principal Financial Officer)

Index of Exhibits

Each exhibit identified below is filed as a part of this Quarterly Report on Form 10-Q. Exhibits included in this filing are designated by an asterisk; all exhibits not so designated are incorporated by reference to a prior filing as indicated.

Exhibit Number	Description
10.1	Amendment No. 1 to Credit Agreement and Extension Agreement, dated as of September 30, 2014, by and among Midcoast Energy Partners, L.P., Midcoast Operating, L.P., the subsidiary guarantors party thereto, the lenders party thereto and Bank of America, N.A., as administrative agent for the lenders (incorporated by reference to Exhibit 10.4 of our Current Report on Form 8-K, filed on October 6, 2014).
10.2	Note Purchase Agreement by and among Midcoast Energy Partners, L.P. and the purchasers named therein, dated as of September 30, 2014 (incorporated by reference to Exhibit 10.1 of our Current Report on Form 8-K, filed on October 6, 2014).
10.3	Guaranty Agreement, dated as of September 30, 2014, made by each guarantor in favor of the purchasers and other holders from time to time of the Notes issued pursuant to the Note Purchase Agreement (incorporated by reference to Exhibit 10.2 of our Current Report on Form 8-K, filed on October 6, 2014).
10.4	Subordination Agreement, dated as of September 30, 2014, by and among Midcoast Energy Partners, L.P., other obligors from time to time party thereto, Enbridge Energy Partners, L.P., and certain of its subsidiaries and affiliates from time to time party thereto in favor of the holders from time to time of the Notes issued pursuant to the Note Purchase Agreement (incorporated by reference to Exhibit 10.3 of our Current Report on Form 8-K, filed on October 6, 2014).
10.5	Amended and Restated Subordination Agreement Subordination Agreement, dated as of September 30, 2014, by and among Midcoast Energy Partners, L.P., Midcoast Operating, L.P., the other credit parties from time to time party thereto and Enbridge Energy Partners, L.P. in favor of Bank of America, N.A., as Administrative Agent (incorporated by reference to Exhibit 10.5 of our Current Report on Form 8-K, filed on October 6, 2014).
31.1*	Certification of Principal Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2*	Certification of Principal Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1*	Certification of Principal Executive Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2*	Certification of Principal Financial Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
101.INS*	XBRL Instance Document.
101.SCH*	XBRL Taxonomy Extension Schema Document.
101.CAL*	XBRL Taxonomy Extension Calculation Linkbase Document.
101.DEF*	XBRL Taxonomy Extension Definition Linkbase Document.
101.LAB*	XBRL Taxonomy Extension Label Linkbase Document.
101.PRE*	XBRL Taxonomy Extension Presentation Linkbase Document.

Exhibit 31.1

CERTIFICATION PURSUANT TO SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, C. Gregory Harper, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of Midcoast Energy Partners, L.P.;

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

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

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

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

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

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

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

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

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

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

Date: November 3, 2014

By: /s/ C. Gregory Harper

C. Gregory Harper
Principal Executive Officer
Midcoast Holdings, L.L.C. (as the General Partner)

Exhibit 31.2

CERTIFICATION PURSUANT TO SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Stephen J. Neyland, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of Midcoast Energy Partners, L.P.;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: November 3, 2014

By: /s/ Stephen J. Neyland

Stephen J. Neyland
Vice President—Finance
(Principal Financial Officer)
Midcoast Holdings, L.L.C. (as the General Partner)

Exhibit 32.1

CERTIFICATION OF PRINCIPAL EXECUTIVE OFFICER
Pursuant to Section 906(a) of the Sarbanes-Oxley Act of 2002
Subsections (a) and (b) of Section 1350, Chapter 63 of Title 18 of the United States Code

The undersigned, being the Principal Executive Officer of Midcoast Energy Partners, L.P., hereby certifies that our Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2014 (the "Quarterly Report") filed with the United States Securities and Exchange Commission pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m(a) or 78o(d)), as amended, fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended, and that the information contained in the Quarterly Report fairly presents, in all material respects, the financial condition and results of operations of Midcoast Energy Partners, L.P.

Date: November 3, 2014

By: /s/ C. Gregory Harper

C. Gregory Harper
Principal Executive Officer
Midcoast Holdings, L.L.C. (as the General Partner)

Exhibit 32.2

CERTIFICATION OF PRINCIPAL FINANCIAL OFFICER
Pursuant to Section 906(a) of the Sarbanes-Oxley Act of 2002
Subsections (a) and (b) of Section 1350, Chapter 63 of Title 18 of the United States Code

The undersigned, being the Principal Financial Officer of Midcoast Energy Partners, L.P., hereby certifies that our Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2014 (the "Quarterly Report") filed with the United States Securities and Exchange Commission pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m(a) or 78o(d)), as amended, fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended, and that the information contained in the Quarterly Report fairly presents, in all material respects, the financial condition and results of operations of Midcoast Energy Partners, L.P.

Date: November 3, 2014

By: /s/ Stephen J. Neyland

Stephen J. Neyland
Vice President—Finance
(Principal Financial Officer)
Midcoast Holdings, L.L.C. (as the General Partner)