
**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 June 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
(State or Other Jurisdiction of
Incorporation or Organization)

61-1714064
(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 August 1, 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 (periods prior to 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 (starting 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 June 30, 2014, we owned a 39% controlling interest in Midcoast Operating, and EEP owned a 61% non-controlling 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 61% non-controlling interest in Midcoast Operating as of June 30, 2014. As of July 1, 2014, we own a 51.6% interest in Midcoast Operating, and EEP owns a 48.4% interest.

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 and our subsequently filed Quarterly Reports on Form 10-Q, which are 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 June 30,		For the six month period ended June 30,	
	2014	2013	2014	2013
	(unaudited; in millions, except per unit amounts)			
Operating revenues:				
Operating revenue (Note 11)	\$1,329.9	\$1,244.9	\$2,919.6	\$2,556.6
Operating revenue—affiliate (Notes 9 and 11)	66.9	54.2	124.1	112.8
	1,396.8	1,299.1	3,043.7	2,669.4
Operating expenses:				
Cost of natural gas and natural gas liquids (Notes 4 and 11)	1,221.4	1,078.5	2,679.9	2,236.6
Cost of natural gas and natural gas liquids—affiliate (Notes 9 and 11) . . .	38.4	34.5	68.6	72.5
Operating and maintenance	56.6	63.2	111.2	120.3
Operating and maintenance—affiliate (Note 9)	27.6	27.8	54.7	54.1
General and administrative	1.6	0.1	3.5	0.1
General and administrative—affiliate (Note 9)	20.0	23.5	45.3	48.0
Depreciation and amortization	36.8	35.3	73.8	70.5
	1,402.4	1,262.9	3,037.0	2,602.1
Operating income (loss)	(5.6)	36.2	6.7	67.3
Interest expense, net (Notes 7 and 9)	2.8	—	6.1	—
Equity in earnings of joint ventures (Note 6)	2.3	—	1.0	—
Other income	0.1	0.1	0.1	0.2
Income (loss) before income tax expense	(6.0)	36.3	1.7	67.5
Income tax expense (Note 12)	0.8	7.8	1.8	8.3
Net income (loss)	(6.8)	28.5	(0.1)	59.2
Less: Net income (loss) attributable to noncontrolling interest	(2.2)	—	4.1	—
Net income (loss) attributable to general and limited partner ownership interest in Midcoast Energy Partners, L.P.	\$ (4.6)	\$ 28.5	\$ (4.2)	\$ 59.2
Net income (loss) attributable to limited partner ownership interest	\$ (4.5)	\$ 10.8	\$ (4.1)	\$ 22.7
Net income (loss) per limited partner unit (basic and diluted) (Note 2)	\$ (0.09)	\$ 0.41	\$ (0.09)	\$ 0.85
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 June 30,		For the six month period ended June 30,	
	2014	2013	2014	2013
	(unaudited; in millions)			
Net income (loss)	\$(6.8)	\$28.5	\$(0.1)	\$59.2
Other comprehensive income (loss), net of tax expense of \$0.0 million, \$0.1 million, \$0.0 million and \$0.1 million, respectively (Note 11)	(1.9)	12.0	(1.6)	11.3
Comprehensive income (loss)	(8.7)	40.5	(1.7)	70.5
Less: Comprehensive income (loss) attributable to:				
Noncontrolling interest (Note 9)	(2.2)	—	4.1	—
Other comprehensive loss allocated to noncontrolling interest (Note 9)	(1.2)	—	(1.0)	—
Comprehensive income (loss) attributable to general and limited partner ownership interests in Midcoast Energy Partners, L.P. . .	<u>\$(5.3)</u>	<u>\$40.5</u>	<u>\$(4.8)</u>	<u>\$70.5</u>

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

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

	For the six month period ended June 30,	
	2014	2013
	(unaudited; in millions)	
Cash provided by operating activities:		
Net income (loss)	\$ (0.1)	\$ 59.2
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Depreciation and amortization	73.8	70.5
Derivative fair value net (gains) losses (Note 11)	6.2	(20.8)
Inventory market price adjustments (Note 4)	3.3	2.5
Distributions from investment in joint ventures	1.0	—
Equity earnings from investment in joint ventures (Note 6)	(1.0)	—
Deferred income taxes (Note 12)	0.9	7.7
Other	0.8	(0.8)
Changes in operating assets and liabilities, net of acquisitions:		
Receivables, trade and other	18.1	(14.1)
Due from General Partner and affiliates	622.0	6.4
Accrued receivables	58.8	276.2
Inventory (Note 4)	(68.1)	(80.8)
Current and long-term other assets (Note 11)	(5.5)	(1.9)
Due to General Partner and affiliates	(484.2)	(2.4)
Accounts payable and other (Notes 3 and 11)	(51.5)	(19.0)
Environmental liabilities (Note 10)	0.2	—
Accrued purchases	1.4	(96.5)
Interest payable	0.5	—
Property and other taxes payable	(1.6)	1.1
Settlement of derivatives	1.3	—
Net cash provided by operating activities	<u>176.3</u>	<u>187.3</u>
Cash used in investing activities:		
Additions to property, plant and equipment (Notes 5 and 14)	(110.3)	(137.4)
Changes in restricted cash (Note 9)	49.0	—
Asset acquisitions	—	(0.9)
Proceeds from the sale of net assets	—	5.0
Investment in joint ventures (Note 9)	(28.1)	(126.7)
Distributions from investment in joint ventures in excess of cumulative earnings	17.7	—
Other	—	(2.2)
Net cash used in investing activities	<u>(71.7)</u>	<u>(262.2)</u>
Cash provided by financing activities:		
Net borrowings under credit facility (Note 7)	140.0	—
Contributions from partners (Note 8)	69.8	194.4
Distributions to partners (Note 8)	(83.3)	(119.5)
Net cash provided by financing activities	<u>126.5</u>	<u>74.9</u>
Net increase in cash and cash equivalents	231.1	—
Cash and cash equivalents at beginning of year	4.9	—
Cash and cash equivalents at end of period	<u>\$ 236.0</u>	<u>\$ —</u>

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

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

	<u>June 30, 2014</u>	<u>December 31, 2013</u>
	(unaudited; in millions)	
ASSETS		
Current assets:		
Cash and cash equivalents (Note 3)	\$ 236.0	\$ 4.9
Restricted cash (Note 9)	12.5	61.5
Receivables, trade and other, net of allowance for doubtful accounts of \$0.5 million at June 30, 2014 and December 31, 2013	21.3	50.3
Due from general partner and affiliates (Note 9)	34.7	654.8
Accrued receivables	134.3	182.2
Inventory (Note 4)	150.4	88.0
Other current assets (Note 11)	35.1	19.1
	<u>624.3</u>	<u>1,060.8</u>
Property, plant and equipment, net (Note 5)	4,118.2	4,082.3
Goodwill	226.5	226.5
Intangibles, net	250.5	255.0
Equity investment in joint ventures (Note 6)	381.6	371.3
Other assets, net (Note 11)	40.7	40.5
	<u>\$5,641.8</u>	<u>\$6,036.4</u>
LIABILITIES AND PARTNERS' CAPITAL		
Current liabilities:		
Due to general partner and affiliates (Note 9)	\$ 40.2	\$ 534.3
Accounts payable and other (Notes 3, 10 and 11)	72.0	114.4
Accrued purchases	456.1	463.3
Property and other taxes payable (Note 12)	18.2	19.8
Interest payable	0.8	0.3
	<u>587.3</u>	<u>1,132.1</u>
Long-term debt (Note 7)	475.0	335.0
Other long-term liabilities (Note 10 and 12)	29.5	16.6
Total liabilities	<u>1,091.8</u>	<u>1,483.7</u>
Commitments and contingencies (Note 10)		
Partners' capital: (Note 8)		
Class A common units (22,610,056 at June 30, 2014 and December 31, 2013)	482.4	495.3
Subordinated units (22,610,056 at June 30, 2014 and December 31, 2013)	1,022.2	1,035.1
General Partner units (922,859 at June 30, 2014 and December 31, 2013)	41.7	42.2
Accumulated other comprehensive loss (Note 11)	(3.7)	(3.1)
Total Midcoast Energy Partners, L.P. partners' capital	<u>1,542.6</u>	<u>1,569.5</u>
Noncontrolling interest	3,007.4	2,983.2
Total partners' capital	<u>4,550.0</u>	<u>4,552.7</u>
	<u>\$5,641.8</u>	<u>\$6,036.4</u>

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 June 18, 2014, we agreed to acquire from EEP, a 12.6% limited partner interest in Midcoast Operating for \$350.0 million in cash, which brought the Partnership's total ownership interest in Midcoast Operating to 51.6%. This transaction closed on July 1, 2014, and represents our first acquisition of additional interests in Midcoast Operating since the Offering. The Partnership financed the transaction entirely with debt through our revolving credit facility, which we refer to as the Credit Agreement. We intend to pursue acquisitions of additional interests in our natural gas assets, held through Midcoast Operating, from EEP. EEP has indicated that it intends to offer us the opportunity to purchase additional interests in Midcoast Operating from time to time, although EEP is not legally obligated to do so. We do not know when, or if, any additional interests will be offered to us to purchase.

Basis of Presentation

The accompanying unaudited interim consolidated financial statements have been prepared in accordance with accounting principles generally accepted in the United States, or GAAP, for interim consolidated financial information and with the instructions to Form 10-Q and Rule 10-01 of Regulation S-X. Accordingly, they 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 June 30, 2014, our results of operations for the three and six month periods ended June 30, 2014, and 2013 and our cash flows for the six month periods ended June 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 six month periods ended June 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.

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. As of June 30, 2014, we owned a 39% controlling interest in Midcoast Operating. We consolidate the results of operations of Midcoast Operating and then record a 61% 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. On June 18, 2014, we agreed to acquire from our affiliate, EEP, a 12.6% limited partner interest in Midcoast Operating for \$350.0 million in cash, which brought our total ownership interest in Midcoast Operating to 51.6%. This transaction closed on July 1, 2014, and represents our first acquisition of additional interests in Midcoast Operating since our initial public offering on November 13, 2013. We financed the transaction entirely with debt through our Credit Agreement.
- 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 \$2.2 million of these costs for the six months ended June 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 revolving credit facility, Midcoast Operating's working capital credit facility and other borrowing arrangements we may enter into from time to time. Prior to our acquiring 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.

<u>Distribution Targets</u>	<u>Portion of Quarterly Distribution Per Unit</u>	<u>Percentage Distributed to Limited Partners</u>	<u>Percentage Distributed to General Partner</u>
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:

	<u>For the three month period ended June 30,</u>		<u>For the six month period ended June 30,</u>	
	<u>2014</u>	<u>2013 ⁽³⁾</u>	<u>2014</u>	<u>2013 ⁽³⁾</u>
	<u>(in millions, except per unit amounts)</u>			
Net income (loss)	\$ (6.8)	\$28.5	\$ (0.1)	\$ 59.2
Less: Net income (loss) attributable to noncontrolling interest	(2.2)	17.4	4.1	36.1
Net income (loss) attributable to general and limited partner interests in Midcoast Energy Partners, L.P.	(4.6)	11.1	(4.2)	23.1
Less distributions:				
Total distributed earnings to our General Partner	(0.3)	(0.2)	(0.6)	(0.3)
Total distributed earnings to our limited partners	(14.7)	(8.3)	(28.8)	(16.7)
Total distributed earnings	(15.0)	(8.5)	(29.4)	(17.0)
Underdistributed (Overdistributed) earnings	\$(19.6)	\$ 2.6	\$(33.6)	\$ 6.1
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 ⁽¹⁾	\$ 0.33	\$0.31	\$ 0.64	\$ 0.63
Underdistributed (Overdistributed) earnings per limited partner unit ⁽²⁾	(0.42)	0.10	(0.73)	0.22
Net income (loss) per limited partner unit (basic and diluted)	\$(0.09)	\$0.41	\$(0.09)	\$ 0.85

⁽¹⁾ Represents the total distributed earnings to limited partners divided by the weighted average number of limited partner interests outstanding for the period.

⁽²⁾ 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⁾ 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 six month periods ended June 30, 2013.

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 \$11.9 million at June 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:

	June 30, 2014	December 31, 2013
	(in millions)	
Materials and supplies	\$ 0.6	\$ 0.6
Crude oil inventory	11.4	12.6
Natural gas and NGL inventory	138.4	74.8
	<u>\$150.4</u>	<u>\$88.0</u>

The “Cost of natural gas and natural gas liquids” on our consolidated statements of income includes charges totaling \$1.8 million and \$1.7 million for the three month periods ended June 30, 2014 and 2013, and \$3.3 million and \$2.5 million for the six month periods ended June 30, 2014 and 2013, 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:

	June 30, 2014	December 31, 2013
	(in millions)	
Land	\$ 11.2	\$ 11.6
Rights-of-way	395.2	380.0
Pipelines	1,784.5	1,741.9
Pumping equipment, buildings and tanks	81.5	79.2
Compressors, meters and other operating equipment	2,048.7	1,993.2
Vehicles, office furniture and equipment	166.5	148.5
Processing and treating plants	513.8	514.4
Construction in progress	153.3	181.4
Total property, plant and equipment	5,154.7	5,050.2
Accumulated depreciation	(1,036.5)	(967.9)
Property, plant and equipment, net	<u>\$ 4,118.2</u>	<u>\$4,082.3</u>

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 that together constructed 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 June 30,		For the six month period ended June 30,	
	2014	2013	2014	2013
	(in millions)			
Operating revenues	\$19.2	\$—	\$24.4	\$—
Operating expenses	\$11.9	\$—	\$20.3	\$—
Net income	\$ 7.2	\$—	\$ 4.1	\$—

7. DEBT

Credit Agreement

On November 13, 2013, we, Midcoast Operating, and our material domestic subsidiaries, entered into a senior revolving credit facility, which we refer to as the Credit Agreement, that 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 12, 2016, subject to four one-year requests for extensions. At June 30, 2014, we had \$475.0 million in outstanding borrowings under the Credit Agreement at a weighted average interest rate of 1.9%. Under the Credit Agreement, MEP had net borrowings of approximately \$140.0 million during the six month period ended June 30, 2014, which includes gross borrowings of \$3,465.0 million and gross repayments of \$3,325.0 million. At June 30, 2014, we were in compliance with the terms of our financial covenants in the Credit Agreement.

Our interest cost of the three and six month periods ended June 30, 2014 and 2013 are detailed below.

	For the three month period ended June 30,		For the six month period ended June 30,	
	2014	2013	2014	2013
	(in millions)			
Interest cost incurred	\$3.0	\$ 5.9	\$6.3	\$11.5
Interest capitalized	0.2	5.9	0.2	11.5
Interest expense, net	<u>\$2.8</u>	<u>\$—</u>	<u>\$6.1</u>	<u>\$ —</u>
Interest cost paid	<u>\$3.0</u>	<u>\$ 5.9</u>	<u>\$5.8</u>	<u>\$11.5</u>

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. The facility is available exclusively to fund working capital borrowings. Borrowings under the facility are scheduled to mature in 2017 and accrue interest at a per annum rate of LIBOR, plus 2.5%. At June 30, 2014, we had no 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 \$1.0 million and \$2.2 million of these costs for the three and six month periods ending June 30, 2014, which is included in "Operating and maintenance" on our consolidated statements of income.

Certain Available Credit

At June 30, 2014, we could borrow approximately \$625.0 million 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
Total credit available under working capital credit facility . . .	250.0
Less: Amounts outstanding under Credit Agreement	<u>475.0</u>
Total amount we could borrow at June 30, 2014	<u><u>\$625.0</u></u>

Fair Value of Debt Obligations

The carrying amount of our borrowings under our Credit Agreement approximates the fair value at June 30, 2014, and December 31, 2013, respectively, due to the short-term nature and frequent repricing of the amounts outstanding under these obligations. The fair value of the outstanding borrowings under our Credit Agreement is included with our long-term debt obligations, since we have the ability and the intent to refinance the amounts outstanding on a long-term basis. The fair value of our long-term debt obligation 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 six month period ended June 30, 2014.

Distribution Declaration Date	Record Date	Distribution Payment Date	Distribution per Unit	Cash Distributed
(in millions, except per unit amounts)				
April 30, 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 six month periods ended June 30, 2014, and 2013.

	For the six month period ended June 30,	
	2014	2013
	(in millions)	
Class A common units:		
Beginning balance	\$ 495.3	\$ —
Net income	(2.1)	—
Distributions	(10.8)	—
Ending balance	<u>\$ 482.4</u>	<u>\$ —</u>
Subordinated units:		
Beginning balance	\$1,035.1	\$ —
Net income	(2.1)	—
Distributions	(10.8)	—
Ending balance	<u>\$1,022.2</u>	<u>\$ —</u>
General Partner units:		
Beginning balance	\$ 42.2	\$ —
Net income	—	—
Distributions	(0.5)	—
Ending balance	<u>\$ 41.7</u>	<u>\$ —</u>
Limited Partner: ⁽¹⁾		
Beginning balance	\$ —	\$4,707.1
Capital contribution	—	194.4
Net income	—	59.2
Distributions	—	(119.5)
Ending balance	<u>\$ —</u>	<u>\$4,841.2</u>
Accumulated other comprehensive income (loss)		
Beginning balance	\$ (3.1)	\$ 7.1
Changes in fair value of derivative financial instruments reclassified to earnings	4.0	(3.6)
Changes in fair value of derivative financial instruments recognized in other comprehensive income (loss)	(4.6)	14.9
Ending balance	<u>\$ (3.7)</u>	<u>\$ 18.4</u>
Noncontrolling interest		
Beginning balance	\$2,983.2	\$ —
Capital contributions	82.3	—
Comprehensive income:		
Net income	4.1	—
Other comprehensive income, net of tax	(1.0)	—
Distributions to noncontrolling interest	(61.2)	—
Ending balance	<u>\$3,007.4</u>	<u>\$ —</u>
Total partners' capital at end of period	<u>\$4,550.0</u>	<u>\$4,859.6</u>

⁽¹⁾ These amounts represent the changes in the capital account for the six month periods ended June 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.

9. RELATED PARTY TRANSACTIONS

Administrative and Workforce Related Services

We do not directly employ any of the individuals responsible for managing or operating our business. In connection with the Offering we entered into an Intercompany Services Agreement with EEP pursuant to which we agreed upon certain aspects of our relationship with EEP, including the provision by EEP or its affiliates to us of certain administrative services and employees, our agreement to reimburse EEP or its affiliates for the cost of such services and employees and certain other matters.

Intercompany Services Agreement

On November 13, 2013, in connection with the closing of the Offering, we entered into an Intercompany Services Agreement with EEP, pursuant to which EEP 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 Intercompany 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 that were in effect prior to November 13, 2013, when the Intercompany Services Agreement became effective. 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. For the six month period ending June 30, 2014, we recognized \$12.5 million as a reduction to “Due to general partner and affiliates” with the offset to “Noncontrolling interest” in our consolidated statements of financial position related to this reduction in amounts payable to EEP for general and administrative expenses.

The following table presents the affiliate amounts incurred by us through EEP for services received pursuant to the Intercompany Services Agreement and the prior 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 June 30,		For the six month period ended June 30,	
	2014	2013	2014	2013
	(in millions)			
Operating and maintenance—affiliate	\$27.6	\$27.8	\$ 54.7	\$ 54.1
General and administrative—affiliate	20.0	23.5	45.3	48.0
Total	<u>\$47.6</u>	<u>\$51.3</u>	<u>\$100.0</u>	<u>\$102.1</u>

These amounts were settled through “Cash” and “Contributions from partners” as reflected on our consolidated statements of cash flows for the six month periods ended June 30, 2014 and 2013 respectively.

Enbridge and Enbridge Management and their respective affiliates allocated direct workforce costs to us for our construction projects of \$2.8 million and \$6.8 million as of June 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 purchase natural gas, NGLs and crude oil from third parties, which subsequently generate operating revenues from sales to Enbridge and its affiliates. The sales to Enbridge and its affiliates are presented in “Operating revenue—affiliate” on our consolidated statements of income. These transactions are entered into at

the market price on the date of sale. Included in our results for the three month periods ended June 30, 2014, and 2013 and the six month periods ended June 30, 2014, and 2013 are operating revenues from sales to Enbridge and its affiliates of \$66.9 million, \$54.2 million, \$124.1 million and \$112.8 million, respectively.

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. Included in our results for the three month periods ended June 30, 2014, and 2013 and the six month periods ended June 30, 2014, and 2013 are costs for natural gas, NGLs and crude oil purchases from Enbridge and its affiliates of \$38.4 million, \$34.5 million, \$68.6 million and \$72.5 million, respectively. 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 six month periods ended June 30, 2014. For the three and six month periods ended June 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

For the three and six month periods ended June 30, 2014, we incurred \$6.1 million and \$11.4 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 six month periods ended June 30, 2013. These expenses are recorded in “Cost of natural gas and natural gas liquids—affiliate” on our consolidated statements of income.

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 \$61.2 million to EEP during the six month period ending June 30, 2014, for its ownership interest in Midcoast Operating. In addition, we paid cash distributions totaling \$7.8 million to EEP for the six month period ending June 30, 2014, for its ownership interest in us. These amounts are reflected in “Distributions to partners” on our consolidated statements of cash flows.

Sale of Accounts Receivable

Certain of our subsidiaries entered into a receivables purchase agreement, dated June 28, 2013, as amended on September 20, 2013, and December 2, 2013, which we refer to as the Receivables Agreement, with an indirect wholly owned subsidiary of Enbridge. Pursuant to the Receivables Agreement, the Enbridge subsidiary purchases on a monthly basis, for cash, current accounts receivables and accrued receivables, or the receivables, of those of our subsidiaries and other subsidiaries of EEP that are parties thereto up to an aggregate monthly maximum of \$450.0 million net of receivables that have not been collected. The Receivables Agreement terminates on December 30, 2016.

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 six month periods ended June 30, 2014, the expense stemming from the discount on the receivables sold was \$0.2 million and \$0.5 million, respectively. For the three and six month periods ended June 30, 2014, we sold to the Enbridge subsidiary and derecognized \$880.2 million and \$1,856.5 million of receivables, respectively. For the three and six month periods ended June 30, 2014, the cash proceeds were \$880.0 million

and \$1,856.0 million which was remitted to the buyer through our centralized treasury system. As of June 30, 2014, \$299.0 million of the receivables were outstanding from customers that had not been collected on behalf of the Enbridge subsidiary.

As of June 30, 2014 and December 31, 2013, we have \$12.5 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 six month periods ended June 30, 2013, we had interest cost incurred and interest capitalized of \$5.9 million and \$11.5 million, respectively.

Derivative Transactions

Our Predecessor has 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 our Predecessor. 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 June 30, 2014, and 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 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, the Partnership elected to prospectively change its 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 sub-group 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 normal purchases and normal sales, or 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:

	June 30, 2014	December 31, 2013
	(in millions)	
Other current assets	\$ 21.3	\$ 10.3
Other assets, net	10.6	10.3
Accounts payable and other	(30.2)	(21.1)
Other long-term liabilities	(12.7)	(0.9)
Due from general partner and affiliates	0.6	—
Due to general partner and affiliates	(0.1)	—
	<u><u>\$ (10.5)</u></u>	<u><u>\$ (1.4)</u></u>

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.

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 “Accumulated other comprehensive income”, also referred to as 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 June 30, 2014, are unrecognized gains of approximately \$1.0 million associated with derivative financial instruments that qualified for and were classified as cash flow hedges of forecasted transactions that were subsequently de-designated. These gains are reclassified to earnings over the periods during which the originally hedged forecasted transactions affect earnings. During the six month period ended June 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 \$8.7 million, representing unrealized net losses from our cash flow hedging activities based on pricing and positions at June 30, 2014, will be reclassified from AOCI to earnings during the next 12 months.

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

	June 30, 2014	December 31, 2013
	(in millions)	
Counterparty Credit Quality ⁽¹⁾		
AAA	\$ 0.2	\$ 0.2
AA	(5.9)	(2.1)
A	(8.0)	(1.1)
Lower than A	3.2	1.6
	<u><u>\$ (10.5)</u></u>	<u><u>\$ (1.4)</u></u>

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

As the net value of our derivative financial instruments has decreased in response to changes in forward commodity prices, our outstanding financial exposure to third parties has also decreased. 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 June 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 June 30, 2014, and December 31, 2013, we had credit concentrations in the following industry sectors, as presented below:

	June 30, 2014	December 31, 2013
	(in millions)	
United States financial institutions and investment banking entities	\$ (7.2)	\$ 2.4
Non-United States financial institutions	(4.7)	0.1
Integrated oil companies	(0.8)	(1.6)
Other	2.2	(2.3)
	<u>\$ (10.5)</u>	<u>\$ (1.4)</u>

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 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

		Asset Derivatives		Liability Derivatives	
		Fair Value at		Fair Value at	
Financial Position Location		June 30, 2014	December 31, 2013	June 30, 2014	December 31, 2013
(in millions)					
Derivatives designated as hedging instruments ⁽¹⁾					
Commodity contracts	Other current assets	\$ 0.9	\$ 2.0	\$ —	\$ (0.6)
Commodity contracts	Other assets	0.7	3.5	—	(0.5)
Commodity contracts	Accounts payable and other	—	1.9	(10.0)	(12.7)
Commodity contracts	Other long-term liabilities	—	0.6	(1.5)	(1.4)
		<u>1.6</u>	<u>8.0</u>	<u>(11.5)</u>	<u>(15.2)</u>
Derivatives not designated as hedging instruments					
Commodity contracts	Other current assets	20.4	9.0	—	(0.1)
Commodity contracts	Other assets	9.9	10.7	—	(3.4)
Commodity contracts	Accounts payable and other	—	5.4	(20.2)	(15.7)
Commodity contracts	Other long-term liabilities	—	—	(11.2)	(0.1)
Commodity contracts	Due from general partner and affiliates	0.6	—	—	—
Commodity contracts	Due to general partner and affiliates	—	—	(0.1)	—
		<u>30.9</u>	<u>25.1</u>	<u>(31.5)</u>	<u>(19.3)</u>
Total derivative instruments		<u>\$32.5</u>	<u>\$33.1</u>	<u>\$(43.0)</u>	<u>\$(34.5)</u>

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

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 June 30, 2014					
Commodity contracts ..	\$ (3.2)	Cost of natural gas and natural gas liquids	\$ (3.8)	Cost of natural gas and natural gas liquids	\$(1.1)
Total	<u>\$ (3.2)</u>		<u>\$ (3.8)</u>		<u>\$(1.1)</u>
For the three month period ended June 30, 2013					
Commodity contracts ..	\$10.0	Cost of natural gas and natural gas liquids	\$ 2.1	Cost of natural gas and natural gas liquids	\$ 1.8
Total	<u>\$10.0</u>		<u>\$ 2.1</u>		<u>\$ 1.8</u>
For the six month period ended June 30, 2014					
Commodity contracts ..	\$ (3.3)	Cost of natural gas and natural gas liquids	\$(10.3)	Cost of natural gas and natural gas liquids	\$ 0.6
Total	<u>\$ (3.3)</u>		<u>\$(10.3)</u>		<u>\$ 0.6</u>
For the six month period ended June 30, 2013					
Commodity contracts ..	\$ 8.4	Cost of natural gas and natural gas liquids	\$ 3.6	Cost of natural gas and natural gas liquids	\$ 2.3
Total	<u>\$ 8.4</u>		<u>\$ 3.6</u>		<u>\$ 2.3</u>

⁽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 Loss

	Cash Flow Hedges (in millions)
Balance at December 31, 2013	\$(3.1)
Other Comprehensive Income before reclassifications ⁽¹⁾	(4.6)
Amounts reclassified from AOCI ^{(2) (3)}	4.0
Net other comprehensive loss	<u>\$(0.6)</u>
Balance at June 30, 2014	<u>\$(3.7)</u>

⁽¹⁾ Excludes NCI loss of \$7.3 million reclassified from AOCI at June 30, 2014.

⁽²⁾ Excludes NCI gain of \$6.3 million reclassified from AOCI at June 30, 2014.

⁽³⁾ 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 June 30,		For the six month period ended June 30,	
	2014	2013	2014	2013
(in millions)				
Losses (gains) on cash flow hedges:				
Commodity Contracts ^{(1) (2)}	\$1.4	\$(2.1)	\$4.0	\$(3.6)
Total Reclassifications from AOCI	<u>\$1.4</u>	<u>\$(2.1)</u>	<u>\$4.0</u>	<u>\$(3.6)</u>

⁽¹⁾ Loss (gain) reported within “cost of natural gas and natural gas liquids” in the consolidated statements of income.

⁽²⁾ Excludes NCI gain of \$2.4 million and \$6.3 million reclassified from AOCI for the three and six month periods ended June 30, 2014.

Effect of Derivative Instruments on Consolidated Statements of Income

Derivatives Not Designated as Hedging Instruments	Location of Gain or (Loss) Recognized in Earnings ⁽¹⁾	For the three month period ended June 30,		For the six month period ended June 30,	
		2014	2013	2014	2013 ⁽⁴⁾
		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⁾	\$ (13.0)	\$ 21.6	\$ (19.4)	\$ 19.2
Commodity contracts	Operating revenue	2.3	—	3.1	—
Commodity contracts	Operating revenue— Affiliate	0.5	—	0.5	—
Total		\$ (10.2)	\$ 21.6	\$ (15.8)	\$ 19.2

⁽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 \$(0.2) million, \$1.1 million, \$(8.7) million and \$0.7 million for the three and six month periods ended June 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 June 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
			(in millions)	Net Amount
Description:				
Derivatives	\$32.5	\$ —	\$32.5	\$ (22.5)
Total	<u>\$32.5</u>	<u>\$ —</u>	<u>\$32.5</u>	<u>\$ (22.5)</u>

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
			(in millions)	Net Amount
Description:				
Derivatives	\$33.1	\$ (12.5)	\$20.6	\$ (1.9)
Total	<u>\$33.1</u>	<u>\$ (12.5)</u>	<u>\$20.6</u>	<u>\$ (1.9)</u>

Offsetting of Financial Liabilities and Derivative Liabilities

As of June 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 (in millions)	Gross Amount Not Offset in the Statement of Financial Position	Net Amount
Description:					
Derivatives	\$(43.0)	\$ —	\$(43.0)	\$22.5	\$(20.5)
Total	<u>\$(43.0)</u>	<u>\$ —</u>	<u>\$(43.0)</u>	<u>\$22.5</u>	<u>\$(20.5)</u>

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 (in millions)	Gross Amount Not Offset in the Statement of Financial Position	Net Amount
Description:					
Derivatives	\$(34.5)	\$12.5	\$ (22.0)	\$ 1.9	\$(20.1)
Total	<u>\$(34.5)</u>	<u>\$12.5</u>	<u>\$ (22.0)</u>	<u>\$ 1.9</u>	<u>\$(20.1)</u>

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 June 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.

	June 30, 2014				December 31, 2013			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
	(in millions)							
Commodity contracts:								
Financial	\$—	\$(6.7)	\$(6.4)	\$(13.1)	\$—	\$(3.4)	\$(6.9)	\$(10.3)
Physical	—	—	5.0	5.0	—	—	0.5	0.5
Commodity options	—	—	(2.4)	(2.4)	—	—	8.4	8.4
Total	<u>\$—</u>	<u>\$(6.7)</u>	<u>\$(3.8)</u>	<u>\$(10.5)</u>	<u>\$—</u>	<u>\$(3.4)</u>	<u>\$ 2.0</u>	<u>\$ (1.4)</u>

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 over-the-counter, or 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 June 30, 2014	Valuation Technique	Unobservable Input	Range ⁽¹⁾			Units
				Lowest	Highest	Weighted Average	
(in millions)							
<i>Commodity Contracts—Financial</i>							
Natural Gas	\$(1.1)	Market Approach	Forward Gas Price	3.95	4.91	4.37	MMBtu
NGLs	\$(5.3)	Market Approach	Forward NGL Price	0.29	2.20	1.33	Gal
<i>Commodity Contracts—Physical</i>							
Natural Gas	\$ 1.2	Market Approach	Forward Gas Price	3.50	5.03	4.31	MMBtu
Crude Oil	\$(2.5)	Market Approach	Forward Crude Oil Price	91.73	109.03	104.63	Bbl
NGLs	\$ 6.3	Market Approach	Forward NGL Price	0.04	2.27	1.19	Gal
<i>Commodity Options</i>							
Natural Gas, Crude and NGLs	<u>\$(2.4)</u>	—	Option Volatility	14%	31%	24%	
<i>Total Fair Value</i>	<u>\$(3.8)</u>						

⁽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.

Quantitative Information About Level 3 Fair Value Measurements

Contract Type	Fair Value at December 31, 2013 ⁽²⁾ (in millions)	Valuation Technique	Unobservable Input	Range ⁽¹⁾			Units
				Lowest	Highest	Weighted Average	
<i>Commodity Contracts—Financial</i>							
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
<i>Commodity Contracts—Physical</i>							
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
<i>Commodity Options</i>							
Natural Gas, Crude and NGLs	<u>\$ 8.4</u>	Option Model	Option Volatility	18%	44%	28%	
<i>Total Fair Value</i>	<u>\$ 2.0</u>						

⁽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 June 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	(7.3)	3.8	(10.5)	(14.0)
Included in other comprehensive income	(3.3)	—	—	(3.3)
Purchases, issuances, sales and settlements:				
Purchases	—	—	0.4	0.4
Sales	—	—	(0.5)	(0.5)
Settlements ⁽²⁾	11.1	0.7	(0.2)	11.6
Ending balance as of June 30, 2014	<u>\$ (6.4)</u>	<u>\$ 5.0</u>	<u>\$ (2.4)</u>	<u>\$ (3.8)</u>
Amount of changes in net assets attributable to the change in unrealized gains or losses related to assets still held at the reporting date	<u>\$ (4.6)</u>	<u>\$ 3.9</u>	<u>\$ (10.3)</u>	<u>\$ (11.0)</u>
Amounts reported in operating revenue	<u>\$ —</u>	<u>\$ 3.6</u>	<u>\$ —</u>	<u>\$ 3.6</u>

⁽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 June 30, 2014, and December 31, 2013.

		At June 30, 2014						At December 31, 2013	
		Commodity	Notional ⁽¹⁾	Wtd. Average Price ⁽²⁾		Fair Value ⁽³⁾		Fair Value ⁽³⁾	
				Receive	Pay	Asset	Liability	Asset	Liability
		(in millions)							
Portion of contracts maturing in 2014									
<i>Swaps</i>									
Receive variable/pay fixed	Natural Gas	832,732	\$ 4.41	\$ 4.36	\$ 0.1	\$—	\$—	\$ —	
	NGL	316,000	\$ 62.97	\$ 60.27	\$ 0.9	\$—	\$ 0.6	\$ (0.4)	
Receive fixed/pay variable	Natural Gas	3,631,800	\$ 4.32	\$ 4.42	\$ 0.3	\$(0.7)	\$ 0.1	\$ (1.0)	
	NGL	1,612,280	\$ 54.87	\$ 58.63	\$ 1.0	\$(7.1)	\$ 4.8	\$(12.7)	
	Crude Oil	470,320	\$ 90.89	\$103.18	\$—	\$(5.8)	\$ 0.3	\$ (5.4)	
Receive variable/pay variable	Natural Gas	32,675,300	\$ 4.37	\$ 4.38	\$ 0.7	\$(1.1)	\$ 0.6	\$ (0.1)	
<i>Physical Contracts</i>									
Receive variable/pay fixed	Natural Gas	79,594	\$ 4.36	\$ 4.36	\$—	\$—	\$—	\$ —	
	NGL	1,355,000	\$ 35.27	\$ 34.13	\$ 1.6	\$(0.1)	\$ 0.9	\$ (0.9)	
	Crude Oil	81,000	\$105.17	\$107.05	\$—	\$(0.1)	\$—	\$ —	
Receive fixed/pay variable	Natural Gas	333,893	\$ 4.41	\$ 4.40	\$—	\$—	\$—	\$ —	
	NGL	2,403,278	\$ 37.70	\$ 38.51	\$ 0.5	\$(2.5)	\$ 0.4	\$ (2.6)	
	Crude Oil	184,000	\$103.96	\$104.85	\$ 0.2	\$(0.3)	\$—	\$ (0.4)	
Receive variable/pay variable	Natural Gas	107,169,373	\$ 4.41	\$ 4.40	\$ 1.3	\$(0.8)	\$ 0.9	\$ (0.4)	
	NGL	13,859,812	\$ 48.43	\$ 48.03	\$ 6.4	\$(0.8)	\$ 5.8	\$ (3.7)	
	Crude Oil	734,242	\$101.94	\$104.89	\$ 0.8	\$(2.9)	\$ 1.1	\$ (1.2)	
Portion of contracts maturing in 2015									
<i>Swaps</i>									
Receive variable/pay fixed	Natural Gas	19,080	\$ 4.47	\$ 4.54	\$—	\$—	\$—	\$ —	
	NGL	82,500	\$ 83.98	\$ 84.84	\$—	\$(0.1)	\$—	\$ —	
	Crude Oil	456,000	\$ 96.90	\$ 92.94	\$ 1.8	\$—	\$—	\$ —	
Receive fixed/pay variable	Natural Gas	596,861	\$ 4.74	\$ 4.51	\$ 0.1	\$—	\$—	\$ —	
	NGL	755,000	\$ 53.11	\$ 54.33	\$ 0.9	\$(1.8)	\$ 1.5	\$ (1.1)	
	Crude Oil	444,650	\$ 92.88	\$ 97.51	\$ 0.3	\$(2.4)	\$ 1.7	\$ —	
Receive variable/pay variable	Natural Gas	19,885,000	\$ 4.29	\$ 4.31	\$ 0.3	\$(0.7)	\$ 0.1	\$ —	
<i>Physical Contracts</i>									
Receive fixed/pay variable	NGL	295,624	\$ 53.31	\$ 54.03	\$ 0.1	\$(0.3)	\$—	\$ —	
Receive variable/pay variable	Natural Gas	79,446,592	\$ 4.29	\$ 4.29	\$ 1.3	\$(0.8)	\$ 0.5	\$ (0.1)	
	NGL	2,977,353	\$ 66.95	\$ 66.50	\$ 1.9	\$(0.5)	\$—	\$ —	
Portion of contracts maturing in 2016									
<i>Swaps</i>									
Receive fixed/pay variable	Crude Oil	—	\$ —	\$ —	\$—	\$—	\$ 0.7	\$ —	
Receive variable/pay fixed	Crude Oil	68,250	\$ 92.49	\$ 90.00	\$ 0.2	\$—	\$—	\$ —	
Receive variable/pay variable	Natural Gas	5,927,000	\$ 4.09	\$ 4.11	\$—	\$(0.1)	\$—	\$ —	
<i>Physical Contracts</i>									
Receive variable/pay variable	Natural Gas	32,721,379	\$ 4.16	\$ 4.16	\$ 0.7	\$(0.6)	\$ 0.1	\$ —	
Portion of contracts maturing in 2017									
<i>Physical Contracts</i>									
Receive variable/pay variable	Natural Gas	13,399,743	\$ 4.38	\$ 4.36	\$ 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 June 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 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 June 30, 2014, and December 31, 2013.

		At June 30, 2014					At December 31, 2013		
		Commodity	Notional ⁽¹⁾	Strike Price ⁽²⁾	Market Price ⁽²⁾	Fair Value ⁽³⁾		Fair Value ⁽³⁾	
						Asset	Liability	Asset	Liability
		(in millions)							
Portion of option contracts maturing in 2014									
Puts (purchased) . . .	Natural Gas	2,208,000	\$ 3.90	\$ 4.46	\$ 0.1	\$—	\$ 0.7	\$—	
	NGL	386,400	\$54.79	\$56.17	\$ 1.3	\$—	\$ 2.9	\$—	
Calls (written)	NGL	230,000	\$60.92	\$58.65	\$—	\$(0.6)	\$—	\$(1.0)	
Puts (written)	Natural Gas	1,472,000	\$ 3.90	\$ 4.46	\$—	\$(0.1)	\$—	\$(0.5)	
Calls (purchased) . .	NGL	46,000	\$50.40	\$45.50	\$ 0.1	\$—	\$—	\$—	
Portion of option contracts maturing in 2015									
Puts (purchased) . . .	Natural Gas	4,015,000	\$ 3.90	\$ 4.22	\$ 1.0	\$—	\$ 1.7	\$—	
	NGL	1,259,250	\$49.40	\$54.10	\$ 4.3	\$—	\$ 6.0	\$—	
	Crude Oil	547,500	\$85.42	\$96.40	\$ 1.2	\$—	\$ 1.8	\$—	
Calls (written)	Natural Gas	1,277,500	\$ 5.05	\$ 4.22	\$—	\$(0.2)	\$—	\$(0.3)	
	NGL	438,000	\$57.05	\$54.83	\$—	\$(2.1)	\$—	\$(1.0)	
	Crude Oil	547,500	\$91.75	\$96.40	\$—	\$(4.9)	\$—	\$(1.9)	
Puts (written)	Natural Gas	1,825,000	\$ 4.08	\$ 4.22	\$—	\$(0.6)	\$—	\$—	
Calls (purchased) . .	Natural Gas	1,277,500	\$ 5.05	\$ 4.22	\$ 0.2	\$—	\$—	\$—	
Portion of option contracts maturing in 2016									
Puts (purchased) . . .	Natural Gas	1,647,000	\$ 3.75	\$ 4.24	\$ 0.4	\$—	\$—	\$—	
	NGL	366,000	\$38.22	\$43.67	\$ 1.3	\$—	\$—	\$—	
	Crude Oil	439,200	\$80.00	\$91.25	\$ 1.5	\$—	\$—	\$—	
Calls (written)	Natural Gas	1,647,000	\$ 4.98	\$ 4.24	\$—	\$(0.3)	\$—	\$—	
	NGL	366,000	\$47.02	\$43.67	\$—	\$(1.8)	\$—	\$—	
	Crude Oil	439,200	\$92.25	\$91.25	\$—	\$(3.4)	\$—	\$—	

⁽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 June 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 gains at June 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% for the six month periods ended June 30, 2014, and 2013. Our income tax expense is \$0.8 million and \$7.8 million for the three month periods ended June 30, 2014 and 2013, and \$1.8 million and \$8.3 million for the six month periods ended June 30, 2014 and 2013.

At June 30, 2014, and December 31, 2013, we have included a current income tax payable of \$0.7 million and \$1.0 million, respectively, in “Property and other taxes payable” on our consolidated statements of financial position. In addition, at June 30, 2014, and December 31, 2013, we have included a deferred income tax payable of \$12.0 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 June 30, 2014			
	Gathering, Processing and Transportation	Logistics and Marketing	Corporate ⁽¹⁾	Total
	(in millions)			
Total revenue	\$694.0	\$1,255.8	\$—	\$1,949.8
Less: Intersegment revenue	524.6	28.4	—	553.0
Operating revenue	169.4	1,227.4	—	1,396.8
Cost of natural gas and natural gas liquids	50.1	1,209.7	—	1,259.8
Segment gross margin	119.3	17.7	—	137.0
Operating and maintenance	67.2	16.8	0.2	84.2
General and administrative	17.1	2.5	2.0	21.6
Depreciation and amortization	34.9	1.9	—	36.8
	119.2	21.2	2.2	142.6
Operating income (loss)	0.1	(3.5)	(2.2)	(5.6)
Interest expense, net	—	—	2.8	2.8
Other income	2.3 ⁽²⁾	—	0.1	2.4
Income (loss) before income tax expense	2.4	(3.5)	(4.9)	(6.0)
Income tax expense	—	—	0.8	0.8
Net income (loss)	2.4	\$ (3.5)	\$(5.7)	\$ (6.8)
Less: Net loss attributable to:				
Noncontrolling interest	—	—	(2.2)	(2.2)
Net income (loss) attributable to general and limited partner ownership interests in Midcoast Energy Partners, L.P. . .	\$ 2.4	\$ (3.5)	\$(3.5)	\$ (4.6)

⁽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.

For the three month period ended June 30, 2013

	Gathering, Processing and Transportation	Logistics and Marketing	Corporate ⁽¹⁾	Total
	(in millions)			
Total revenue	\$706.6	\$1,128.2	\$—	\$1,834.8
Less: Intersegment revenue	<u>507.2</u>	<u>28.5</u>	<u>—</u>	<u>535.7</u>
Operating revenue	199.4	1,099.7	—	1,299.1
Cost of natural gas and natural gas liquids	<u>50.8</u>	<u>1,062.2</u>	<u>—</u>	<u>1,113.0</u>
Segment gross margin	148.6	37.5	—	186.1
Operating and maintenance	73.0	18.0	—	91.0
General and administrative	20.6	3.0	—	23.6
Depreciation and amortization	<u>33.7</u>	<u>1.6</u>	<u>—</u>	<u>35.3</u>
	<u>127.3</u>	<u>22.6</u>	<u>—</u>	<u>149.9</u>
Operating income	21.3	14.9	—	36.2
Other income	<u>—</u>	<u>—</u>	<u>0.1</u>	<u>0.1</u>
Income before income tax expense	21.3	14.9	0.1	36.3
Income tax expense	<u>—</u>	<u>—</u>	<u>7.8</u>	<u>7.8</u>
Net income (loss)	<u>\$ 21.3</u>	<u>\$ 14.9</u>	<u>\$(7.7)</u>	<u>\$ 28.5</u>

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

As of and for the six month period ended June 30, 2014

	Gathering, Processing and Transportation	Logistics and Marketing	Corporate ⁽¹⁾	Total
	(in millions)			
Total revenue	\$ 1,419.0	\$2,728.8	\$ —	\$4,147.8
Less: Intersegment revenue	1,046.3	57.8	—	1,104.1
Operating revenue	372.7	2,671.0	—	3,043.7
Cost of natural gas and natural gas liquids	134.9	2,613.6	—	2,748.5
Segment gross margin	237.8	57.4	—	295.2
Operating and maintenance	131.6	34.1	0.2	165.9
General and administrative	41.1	5.7	2.0	48.8
Depreciation and amortization	69.9	3.9	—	73.8
	242.6	43.7	2.2	288.5
Operating income (loss)	(4.8)	13.7	(2.2)	6.7
Interest expense, net	—	—	6.1	6.1
Other income	1.1 ⁽³⁾	—	—	1.1
Income (loss) before income tax expense	(3.7)	13.7	(8.3)	1.7
Income tax expense	—	—	1.8	1.8
Net income (loss)	(3.7)	13.7	(10.1)	(0.1)
Less: Net income attributable to:				
Noncontrolling interest	—	—	4.1	4.1
Net income (loss) attributable to general and limited partner ownership interests in Midcoast Energy Partners, L.P. . .	\$ (3.7)	\$ 13.7	\$ (14.2)	\$ (4.2)
Total assets	\$4,917.7 ⁽²⁾	\$ 394.0	\$330.1	\$5,641.8
Capital expenditures (excluding acquisitions)	\$ 99.9	\$ 5.1	\$ 1.6	\$ 106.6

⁽¹⁾ Corporate consists of income taxes and interest expense, 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.

⁽³⁾ Other income for our Gathering, Processing and Transportation segment includes our equity investment in the Texas Express NGL system which began recognizing operating costs during the fourth quarter of 2013.

As of and for the six month period ended June 30, 2013

	Gathering, Processing and Transportation	Logistics and Marketing	Corporate ⁽¹⁾	Total
	(in millions)			
Total revenue	\$ 1,365.8	\$2,351.2	\$ —	\$3,717.0
Less: Intersegment revenue	994.2	53.4	—	1,047.6
Operating revenue	371.6	2,297.8	—	2,669.4
Cost of natural gas and natural gas liquids	68.2	2,240.9	—	2,309.1
Segment gross margin	303.4	56.9	—	360.3
Operating and maintenance	137.2	37.2	—	174.4
General and administrative	42.5	5.6	—	48.1
Depreciation and amortization	67.2	3.3	—	70.5
	246.9	46.1	—	293.0
Operating income	56.5	10.8	—	67.3
Other income	—	—	0.2	0.2
Income before income tax expense	56.5	10.8	0.2	67.5
Income tax expense	—	—	8.3	8.3
Net income (loss)	\$ 56.5	\$ 10.8	\$ (8.1)	\$ 59.2
Total assets	\$4,810.9 ⁽²⁾	\$ 691.5	\$55.0	\$5,557.4
Capital expenditures (excluding acquisitions)	\$ 125.5	\$ 8.2	\$ —	\$ 133.7

⁽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 venture”):

	For the six month period ended June 30,	
	2014	2013
	(in millions)	
Additions to property, plant and equipment	\$110.3	\$137.4
Decrease in construction payables	(3.7)	(3.7)
Total capital expenditures (excluding “Investment in joint venture”)	\$106.6	\$133.7

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. The adoption of the pronouncement is not anticipated to have a material impact on our consolidated financial statements. This accounting update is effective for annual and interim periods beginning after December 15, 2014, and is to be applied prospectively.

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. The impact of the adoption of the pronouncement on our consolidated financial statements is still being evaluated. 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.

16. SUBSEQUENT EVENTS

Drop Down Acquisition of Additional Interests in Midcoast Operating

On June 18, 2014, we agreed to acquire from EEP a 12.6% limited partner interest in Midcoast Operating for \$350.0 million in cash, which brought our total ownership interest in Midcoast Operating to 51.6%. This transaction closed on July 1, 2014 and 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 financed the transaction entirely with debt through our Credit Agreement.

Purchase of Interest Rate Swaps

On July 2, 2014, we entered into interest rate swaps with a total notional amount of \$200.0 million to hedge future debt issuances for the Partnership. The interest rate swaps have an effective date of December 31, 2014, and a maturity of 5 years.

Distribution to Partners

On July 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 August 14, 2014. The distribution will be paid to unitholders of record as of August 7, 2014, of our available cash of \$15.0 million at June 30, 2014, or \$0.3250 per limited partner unit. We will pay \$6.9 million to our public Class A common unitholders, while \$8.1 million in the aggregate will be paid to EEP with respect to its Class A common units and subordinated units and Midcoast Holdings, with respect to its general partner interest.

Midcoast Operating Distribution

On July 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 August 7, 2014. Midcoast Operating will pay \$23.5 million to us and \$22.0 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 (periods prior to 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 (periods beginning on or 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. As of June 30, 2014, we consolidated the results of operations of Midcoast Operating and recorded a 61% 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. On June 18, 2014, we agreed to acquire from our affiliate, EEP, a 12.6% limited partner interest in Midcoast Operating for \$350.0 million in cash, which brought our total ownership interest in Midcoast Operating to 51.6%. This transaction closed on July 1, 2014, and represents our first acquisition of additional interests in Midcoast Operating since our initial public offering on November 13, 2013. We financed the transaction entirely with debt through our Credit Agreement.
- 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, 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 \$2.2 million of these costs for the six months ended June 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 read "Liquidity and Capital Resources—Financial Support Agreement."
- We incur interest expense under our revolving credit facility, Midcoast Operating's working capital credit facility and other borrowing arrangements we may enter into from time to time. Prior to our acquiring 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.

RESULTS OF OPERATIONS—OVERVIEW

We provide services to our customers and returns for our unitholders primarily through the following activities:

- Gathering, treating, processing and transportation of natural gas and natural gas liquids, or NGLs, through pipelines and related facilities; and
- Supply, transportation and sales services, including purchasing and selling natural gas and NGLs.

We conduct our business through two business segments: Gathering, Processing and Transportation; and Logistics and Marketing. These segments are strategic business units established by senior management 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 six month periods ended June 30, 2014, and 2013.

	For the three month period ended June 30,		For the six month period ended June 30,	
	2014	2013	2014	2013
	(in millions)			
Operating income (loss)				
Gathering, Processing and Transportation	\$ 0.1	\$21.3	\$ (4.8)	\$56.5
Logistics and Marketing	(3.5)	14.9	13.7	10.8
Corporate	(2.2)	—	(2.2)	—
Total operating income (loss)	(5.6)	36.2	6.7	67.3
Interest expense, net	2.8	—	6.1	—
Other income	2.4	0.1	1.1	0.2
Income tax expense	0.8	7.8	1.8	8.3
Net income	<u>\$(6.8)</u>	<u>\$28.5</u>	<u>\$ (0.1)</u>	<u>\$59.2</u>

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 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 six month periods ended June 30, 2014, decreased \$21.2 million and \$61.3 million, respectively, when compared to the same periods in 2013 primarily due to the following:

- Decreased operating income of approximately \$17.4 million and \$35.3 million for the three and six month periods ended June 30, 2014, respectively, primarily due to reduced average daily volumes on our major systems primarily attributable to reduced and delayed drilling activity in the Anadarko and East Texas regions;
- Decreased operating income of \$17.7 million and \$18.8 million for the three and six month periods, respectively, ended June 30, 2014, in non-cash, mark-to-market net losses from derivative instruments that do not qualify for hedge accounting treatment, when compared to the same period in 2013;
- Decreased operating revenue less the cost of natural gas derived from keep-whole processing earnings of \$4.9 million and \$12.4 million for the three and six month periods, respectively, ended June 30, 2014, when compared to the same period in 2013 due to a decline in total NGL production and the Avinger plant shutdown from early January until mid-February 2014;

- Decreased operating income of approximately \$3.0 million for the six month period ended June 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;
- Decreased operating income of \$1.3 million and \$2.2 million for the three and six month periods ended June 30, 2014, respectively, due to reduced pricing spreads between our Conway and Mont Belvieu market hubs when compared with the same periods in 2013;
- Increased operating revenues of \$4.4 million for the three and six month periods ended June 30, 2014, related to contractual minimum volume commitment contracts in which our customer has not moved the required volumes;
- Increased depreciation and amortization expense of \$1.2 and \$2.7 million for the three and six month periods ended June 30, 2014, respectively, as compared with the same periods in 2013 due to additional assets that were put in service; and
- Decreased operating and maintenance costs of \$5.8 million and \$5.6 million for the three and six month periods ended June 30, 2014, respectively, as compared to the same period in 2013 due primarily to decreased rent and lease related costs.
- Decreased general and administrative costs of \$3.5 million and \$1.4 million for the three and six month periods ended June 30, 2014, respectively, as compared to the same period in 2013 due primarily to lower administrative costs and rents and leases.

Logistics and Marketing

The operating income of our Logistics and Marketing segment decreased \$18.4 million and increased \$2.9 million for the three and six month periods ended June 30, 2014, respectively, when compared to the same periods in 2013 due to the following:

- Increased operating income of \$0.7 million and \$10.8 million for the three and six month periods ended June 30, 2014, respectively, as compared with the same periods in 2013 due to increased margins from pricing differentials. Higher operating income for the six month period ended June 30, 2014 were 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 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.
- Offsetting the increase was a decrease in non-cash, mark-to-market net gains of \$15.4 million and \$8.2 million for the three and six month periods ended June 30, 2014, primarily from the non-qualifying commodity derivatives we use to economically hedge a portion of the NGLs and the natural gas stream resulting from the operating activities of our Logistics and Marketing segment.
- Decreased operating income of \$3.9 million for the three month period ended June 30, 2014 as a result of a decline in our trucking and NGL marketing due in part to lower volumes received from our Gathering, Processing and Transportation segment.

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 June 30,		For the six month period ended June 30,	
	2014	2013	2014	2013
	(in millions)			
Gathering, Processing and Transportation segment				
Hedge ineffectiveness	\$ (1.1)	\$ 1.8	\$ 0.6	\$ 2.3
Non-qualified hedges	(9.2)	5.6	(10.6)	6.5
Logistics and Marketing segment				
Non-qualified hedges	(0.5)	14.9	3.8	12.0
Derivative fair value net gains (losses)	<u><u>\$(10.8)</u></u>	<u><u>\$22.3</u></u>	<u><u>\$ (6.2)</u></u>	<u><u>\$20.8</u></u>

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 June 30,		For the six month period ended June 30,	
	2014	2013	2014	2013
	(in millions)			
Operating revenues	\$ 169.4	\$ 199.4	\$ 372.7	\$ 371.6
Cost of natural gas and natural gas liquids	<u>50.1</u>	<u>50.8</u>	<u>134.9</u>	<u>68.2</u>
Segment gross margin	<u>119.3</u>	<u>148.6</u>	<u>237.8</u>	<u>303.4</u>
Operating and maintenance	67.2	73.0	131.6	137.2
General and administrative	17.1	20.6	41.1	42.5
Depreciation and amortization	<u>34.9</u>	<u>33.7</u>	<u>69.9</u>	<u>67.2</u>
Operating expenses	<u>119.2</u>	<u>127.3</u>	<u>242.6</u>	<u>246.9</u>
Operating income (loss)	0.1	21.3	(4.8)	56.5
Other income	<u>2.3</u>	<u>—</u>	<u>1.1</u>	<u>—</u>
Net income (loss)	<u><u>\$ 2.4</u></u>	<u><u>\$ 21.3</u></u>	<u><u>\$ (3.7)</u></u>	<u><u>\$ 56.5</u></u>
Operating Statistics (MMBtu/d)				
East Texas	1,029,000	1,211,000	1,000,000	1,231,000
Anadarko	826,000	972,000	825,000	968,000
North Texas	<u>300,000</u>	<u>344,000</u>	<u>286,000</u>	<u>338,000</u>
Total	<u><u>2,155,000</u></u>	<u><u>2,527,000</u></u>	<u><u>2,111,000</u></u>	<u><u>2,537,000</u></u>
NGL Production (Bpd)	<u><u>83,480</u></u>	<u><u>91,251</u></u>	<u><u>82,004</u></u>	<u><u>89,900</u></u>

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

The operating income of our Gathering, Processing and Transportation segment for the three month period ended June 30, 2014, decreased \$21.2 million, as compared with the same period in 2013. The most significant area affected was segment gross margin, which decreased \$29.3 million for the three month period ended June 30, 2014, as compared with the same period in 2013.

The operating results of our Gathering, Processing and Transportation segment experienced a decrease in non-cash, mark-to-market net gains of \$17.7 million for the three month period ended June 30, 2014, compared to the same period in 2013 primarily related to reduced gains in the three months ended June 30, 2014, on our equity gas 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.

The segment gross margin for our Gathering, Processing and Transportation segment was affected by the reduced production volumes which negatively affected segment gross margin by approximately \$17.4 million for the three month period ended June 30, 2014, compared to the same period in 2013. The average daily volumes of our major systems for the three month period ended June 30, 2014, decreased by 372,000 MMBtu/d, or 15%, when compared to the same period in 2013. The average NGL production for the three month period ended June 30, 2014, decreased 7,771 Bpd, or 9%, when compared to the same period in 2013. The decrease in volumes in the Anadarko region was primarily attributable to reduced drilling activity by certain producers, and the loss of a major customer. The decrease in 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 volume outlook on our systems is expected to improve as we progress through 2014. We expect producer drilling plans to accelerate in each of our asset regions later in the year. 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.

A variable element of the operating results is derived from processing natural gas on our systems. Under percentage of liquids, or POL, contracts, we are required to pay producers a contractually fixed recovery of NGLs regardless of the NGLs we physically produce or our ability to process the NGLs from the natural gas stream. NGLs that are produced in excess of this contractual obligation in addition to 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 June 30, 2014, decreased \$4.9 million from the same period in 2013.

Operating income decreased \$1.3 million for the three month period ended June 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. For the three months ended June 30, 2014, the prevailing price for NGLs increased approximately 17% per composite barrel at the Conway pricing hub, while increasing approximately 10% per composite barrel at the Mont Belvieu pricing hub, in each case as compared with the prevailing composite barrel prices for the same period in 2013.

The decrease in segment gross margin was offset in part by an increase of \$4.4 million in operating revenues for the three months ended June 30, 2014, from contractual minimum volume commitment contracts in which our customer has not moved the required volumes.

The operating and maintenance costs of our Gathering, Processing and Transportation segment decreased \$5.8 million for the three month period ended June 30, 2014, compared to the same period in 2013 due primarily to decreased rent and lease related costs.

The general and administrative costs of our Gathering, Processing and Transportation segment for the three month period ended June 30, 2014, decreased by \$3.5 million compared with the same period in 2013 due primarily to lower administrative costs and rents and leases.

Depreciation and amortization expense of our Gathering, Processing and Transportation segment increased \$1.2 million for the three month period ended June 30, 2014, compared with the same period of 2013 due to additional assets that were put in service.

We recognized \$2.3 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. The Texas Express NGL system operates using ship or pay contracts. These ship or pay contracts contain make-up rights provisions, which are earned when minimum volume commitments are not utilized during the contract period but are also subject to contractual expiration periods. Revenue associated with these make-up rights is deferred when more than a remote chance of future utilization exists. For the three month period ended June 30, 2014, the deferred revenue on the ship or pay contracts amounted to \$1.1 million.

Six month period ended June 30, 2014, compared with six month period ended June 30, 2013

The operating income of our Gathering, Processing and Transportation segment for the six month period ended June 30, 2014, decreased \$61.3 million, as compared with the same period of 2013. The most significant area affected was segment gross margin, which decreased \$65.6 million for the six month period ended June 30, 2014, as compared with the same period in 2013.

The segment gross margin for our Gathering, Processing and Transportation segment was affected by reduced production volumes which negatively affected segment gross margin by approximately \$35.3 million for the six month period ended June 30, 2014, compared to the same period in 2013. The average daily volumes of our major systems for the six month period ended June 30, 2014, decreased by approximately 426,000 MMBtu/d, or 17%, when compared to the same period in 2013. The average NGL production for the six month period ended June 30, 2014, decreased by 7,896 Bpd, or 9%, when compared to the same period in 2013. The decrease in volumes in the Anadarko region was primarily attributable to reduced drilling activity by certain producers, and the loss of a major customer. The decrease in volumes in the East Texas region was primarily attributable to reduced dry gas drilling, and delayed drilling activity and well completions.

Non-cash, mark-to-market net gains decreased \$18.8 million for the six month period ended June 30, 2014, when compared to the same period in 2013 due to fractionation margins, representing the relative difference between the price we receive from the sale of NGLs and condensate and the corresponding cost of natural gas we purchase for processing, widening during the six month period ended June 30, 2014, when compared to the same period in 2013 as a result of lower natural gas forward prices.

Operating revenue less the cost of natural gas derived from keep-whole earnings for the six month period ended June 30, 2014, decreased \$12.4 million from the same period in 2013.

Operating income decreased approximately \$3.0 million for the six month period ended June 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.

Operating income decreased \$2.2 million for the six month period ended June 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. For the six months ended June 30, 2014, the prevailing price for NGLs increased approximately 20% per composite barrel at the Conway pricing hub, while increasing approximately 13% per composite barrel at the Mont Belvieu pricing hub, in each case as compared with the prevailing composite barrel prices for the same period in 2013.

The decrease in segment gross margin was partially offset by an increase of \$4.4 million for the six months ended June 30, 2014, from contractual make-up rights earned for cumulative minimum volumes that will not be met before the expiration of the contracts.

Operating and maintenance costs of our Gathering, Processing and Transportation segment decreased \$5.6 million for the six month period ended June 30, 2014, compared to the same period in 2013 primarily related to lower rents and leases and pipeline integrity.

General and administrative costs of our Gathering, Processing and Transportation segment decreased \$1.4 million due to lower administrative costs and rents and leases, for the six month period ended June 30, 2014, when compared with the six month period ended June 30, 2013.

Depreciation and amortization expense for our Gathering, Processing and Transportation segment increased \$2.7 million, for the six month period ended June 30, 2014, compared with the same period of 2013 due to additional assets that were put in service.

We recognized \$1.0 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. The Texas Express NGL system operates using ship or pay contracts. These ship or pay contracts contain make-up rights provisions, which are earned when minimum volume commitments are not utilized during the contract period but are also subject to contractual expiration periods. Revenue associated with these make-up rights is deferred when more than a remote chance of future utilization exists. For the six month period ended June 30, 2014, the deferred revenue on the ship or pay contracts amounted to \$3.2 million.

Future Prospects for Gathering, Processing and Transportation

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.

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. We expect our Beckville processing plant to be capable of processing approximately 150 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 million and expect it to commence service in early 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, at June 30, 2014. On July 1, 2014, the Partnership acquired an additional 12.6% interest in Midcoast Operating from EEP for \$350.0 million. The Partnership’s and EEP’s ownership in Midcoast Operating is 51.6% and 48.4%, respectively, after the transaction date. For additional information on this transaction, see Item 2. *Management’s Discussion and Analysis of Financial Condition and Results of Operations—Subsequent Events*.

Logistics and Marketing

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

	<u>For the three month period ended June 30,</u>		<u>For the six month period ended June 30,</u>	
	<u>2014</u>	<u>2013</u>	<u>2014</u>	<u>2013</u>
	<u>(in millions)</u>			
Operating revenues	\$1,227.4	\$1,099.7	\$2,671.0	\$2,297.8
Cost of natural gas and natural gas liquids	1,209.7	1,062.2	2,613.6	2,240.9
Segment gross margin	17.7	37.5	57.4	56.9
Operating and maintenance	16.8	18.0	34.1	37.2
General and administrative	2.5	3.0	5.7	5.6
Depreciation and amortization	1.9	1.6	3.9	3.3
Operating expenses	21.2	22.6	43.7	46.1
Operating income (loss)	<u>\$ (3.5)</u>	<u>\$ 14.9</u>	<u>\$ 13.7</u>	<u>\$ 10.8</u>

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 and NGLs received from producers on our Gathering, Processing and Transportation segment pipeline assets to customers utilizing the natural gas. 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, which we can use to transport natural gas to primary markets where it can be sold to major natural gas 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 June 30, 2014, compared with three month period ended June 30, 2013

The operating income of our Logistics and Marketing segment for the three month period ended June 30, 2014, decreased \$18.4 million, as compared with the same period in 2013. The most significant area affected was segment gross margin which decreased \$19.8 million for the three month period ended June 30, 2014, as compared with the same period in 2013.

The operating results of our Logistics and Marketing segment experienced a decrease in non-cash, mark-to-market net gains of \$15.4 million for the three month period ended June 30, 2014, compared to the same period in 2013 primarily from the non-qualifying commodity derivatives we use to economically hedge a portion of the NGLs and the natural gas stream resulting from the operating activities of our Logistics and Marketing segment.

Our segment gross margin declined \$3.9 million for the three month period ended June 30, 2014 when compared with the same period in 2013 in our trucking and NGL marketing business due in part to lower volumes received from our Gathering, Processing and Transportation segment.

Operating and maintenance costs of our Logistics and Marketing segment were \$1.2 million lower for the three month period ended June 30, 2014, compared with the three month period ended June 30, 2013 due to lower volumes in our trucking and NGL marketing business, which reduced the amount of required labor and fuel costs.

General and administrative costs of our Logistics and Marketing segment were relatively flat for the three month period ended June 30, 2014, when compared with the three month period ended June 30, 2013.

Depreciation and amortization expense for the three month period ended June 30, 2014, was also relatively flat when compared with the three month period ended June 30, 2013.

Six month period ended June 30, 2014, compared with six month period ended June 30, 2013

The operating income of our Logistics and Marketing segment for the six month period ended June 30, 2014, increased \$2.9 million, as compared with the same period in 2013.

Segment gross margin increased \$10.8 million for the six month period ended June 30, 2014, as compared with the same period in 2013 due to increased margins from pricing differentials. For the six months ended June 30, 2014, the prevailing price for NGLs increased approximately 13% per composite barrel at the Mont Belvieu pricing hub, while increasing approximately 20% per composite barrel at the Conway pricing hub, in each case as compared with the prevailing composite barrel prices for the same period in 2013. Higher operating income for the six month period ended June 30, 2014 were 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 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.

Offsetting the segment gross margin increase was a decrease in non-cash, mark-to-market net gains of \$8.2 million for the six month period ended June 30, 2014, compared to the same period in 2013 primarily from the non-qualifying commodity derivatives we use to economically hedge a portion of the NGLs and the natural gas stream resulting from the operating activities of our Logistics and Marketing segment.

Operating and maintenance costs decreased \$3.1 million for the six month period ended June 30, 2014, as compared with the same period in 2013 primarily due to lower administrative costs.

General and administrative costs were relatively flat for the six month period ended June 30, 2014, compared to the six month period ended June 30, 2013.

Depreciation and amortization expense for the six month period ended June 30, 2014, was also relatively flat when compared to the six month period ended June 30, 2013.

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 June 30,		For the six month period ended June 30,	
	2014	2013	2014	2013
	(in millions)			
Operating and maintenance	\$ 0.2	\$—	\$ 0.2	\$—
General and administrative	2.0	—	2.0	—
Operating expenses	2.2	—	2.2	—
Operating loss	(2.2)	—	(2.2)	—
Interest expense, net	2.8	—	6.1	—
Other income	0.1	0.1	—	0.2
Income tax expense	0.8	7.8	1.8	8.3
Net loss	(5.7)	(7.7)	(10.1)	(8.1)
Net income (loss) attributable to noncontrolling interests	(2.2)	—	4.1	—
Net loss attributable to general and limited partners	<u>\$(3.5)</u>	<u>\$(7.7)</u>	<u>\$(14.2)</u>	<u>\$(8.1)</u>

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

	For the three month period ended June 30,		For the six month period ended June 30,	
	2014	2013 ⁽¹⁾	2014	2013 ⁽¹⁾
	(in millions)			
Interest cost incurred	\$3.0	\$ 5.9	\$6.3	\$11.5
Interest capitalized	0.2	5.9	0.2	11.5
Interest expense, net	<u>\$2.8</u>	<u>\$—</u>	<u>\$6.1</u>	<u>\$—</u>
Interest cost paid	<u>\$3.0</u>	<u>\$ 5.9</u>	<u>\$5.8</u>	<u>\$11.5</u>
Weighted average interest rate ⁽²⁾	2.0%	—	2.1%	—

⁽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 June 30, 2013, MEP had no outstanding debt and no weighted average interest rate.

Three month period ended June 30, 2014, compared with three month period ended June 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 \$0.8 million and \$7.8 million for the three month periods ended June 30, 2014, and June 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, as discussed in Note 12. *Income Taxes*. The Texas Legislature passed House Bill 500, or HB 500, and the tax bill was subsequently signed into law in June 2013. The most significant change in the law for us is that HB 500 allows a pipeline company that transports oil, gas, or other petroleum products owned by others to subtract as Cost of Goods Sold, or COGS, its depreciation, operations, and maintenance costs related to the services provided. Under the new law, we are allowed additional deductions against income for Texas margin tax purposes. The decrease in income taxes period-to-period is a result of the change in this law.

Six month period ended June 30, 2014, compared with six month period ended June 30, 2013

Our income tax expense of \$1.8 million and \$8.3 million for the six month periods ended June 30, 2014, and June 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, as discussed in Note 12. *Income Taxes*.

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 provides 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. In addition, 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 revolving credit facility 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 June 18, 2014, we agreed to acquire from EEP, a 12.6% limited partner interest in Midcoast Operating for \$350.0 million in cash, which brought our total ownership interest in Midcoast Operating to 51.6%. This transaction closed on July 1, 2014, and represents our first acquisition of additional interests in Midcoast Operating since the Offering. The Partnership financed the transaction entirely with debt through our Credit Agreement. 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. We do not know when, or if, any additional interests will be offered to us to purchase.

Credit Facility

On November 13, 2013, we, Midcoast Operating, and our material domestic subsidiaries, entered into the Credit Agreement, that permits aggregate borrowings of up to, at any one time outstanding, \$850.0 million. The facility matures in three years, subject to four one-year requests for extensions. At June 30, 2014, we had \$475.0 million in outstanding borrowings under the Credit Agreement at a weighted average interest rate of 1.9%. Under the Credit Agreement, MEP had net borrowings of approximately \$140.0 million during the six month period ended June 30, 2014, which includes gross borrowings of \$3,465.0 million and gross repayments of \$3,325.0 million. At June 30, 2014, we were in compliance with the terms of our financial covenants in the Credit Agreement.

At June 30, 2014, we could borrow approximately \$625.0 million under the terms of our Credit Agreement and working capital credit facility, determined as follows:

	(in millions)
Total credit available under Credit Agreement	\$850.0
Total credit available under working capital credit facility	250.0
Less: Amounts outstanding under Credit Agreement	475.0
Total amount we could borrow at June 30, 2014	<u>\$625.0</u>

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. The facility is available exclusively to fund working capital borrowings. Borrowings under the facility are scheduled to mature in 2017 and accrue interest at a per annum rate of LIBOR, plus 2.5%. At June 30, 2014, we had no outstanding borrowings under this facility.

Financial Support Agreement

On November 13, 2013, Midcoast Operating entered into a Financial Support Agreement, between Midcoast Operating and 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 would incur under the Financial Support Agreement ranges 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. Based on the Partnership's 39% controlling interest in Midcoast Operating, the Partnership incurred \$1.0 million and \$2.2 million of these annual costs for the three and six month periods ending June 30, 2014, which is included in "Operating and maintenance" on our consolidated statements of income.

Available Liquidity

Our primary sources of liquidity are provided by the Credit Agreement and our working capital facility. As set forth in the following table, we had approximately \$861.0 million of liquidity available to us at June 30, 2014, to meet our ongoing operational, investment and financing needs.

	(in millions)
Cash and cash equivalents	\$236.0
Total credit available under Credit Agreement	850.0
Total credit available under working capital credit facility	250.0
Less: Amounts outstanding under Credit Agreement	<u>475.0</u>
Total	<u><u>\$861.0</u></u>

Sale of Accounts Receivable

Certain of our subsidiaries entered into a receivables purchase agreement, dated June 28, 2013, as amended on September 20, 2013, and December 2, 2013, which we refer to as the Receivables Agreement, with an indirect wholly owned subsidiary of Enbridge. Pursuant to the Receivables Agreement, the Enbridge subsidiary purchases on a monthly basis, for cash, current accounts receivables and accrued receivables, or the receivables, of those of our subsidiaries and other subsidiaries of EEP that are parties thereto up to an aggregate monthly maximum of \$450.0 million net of receivables that have not been collected. The Receivables Agreement terminates on December 30, 2016.

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 six month periods ended June 30, 2014, the expense stemming from the discount on the receivables sold was \$0.2 million and \$0.5 million, respectively. For the three and six month periods ended June 30, 2014, we sold to the Enbridge subsidiary and derecognized \$880.2 million and \$1,856.5 million of receivables,

respectively. For the three and six month periods ended June 30, 2014, the cash proceeds were \$880.0 million and \$1,856.0 million which was remitted to the buyer through our centralized treasury system. As of June 30, 2014, \$299.0 million of the receivables were outstanding from customers that had not been collected on behalf of the Enbridge subsidiary.

As of June 30, 2014 and December 31, 2013, we have \$12.5 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.

Cash Requirements

Capital Spending

We categorize our capital expenditures as either maintenance or expansion capital expenditures. Maintenance capital expenditures are cash expenditures that are made to maintain our asset base, operating capacity or operating income or to maintain the existing useful life of any of our capital assets, in each case over the long term. 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 a portion of our expenditures for connecting natural gas wells, or well-connects, to our natural gas gathering systems as maintenance capital expenditures. We expect to incur continuing annual maintenance capital expenditures primarily for well-connects and for pipeline integrity measures to ensure both regulatory compliance and to maintain the overall integrity of our pipeline systems. Expenditure levels will increase as pipelines age and require higher levels of inspection, maintenance and capital replacement. We also anticipate that maintenance capital expenditures will increase due to the growth of our pipeline systems. We expect to fund our proportional share of maintenance capital expenditures through operating cash flows.

Expansion capital expenditures are cash expenditures incurred for acquisitions or capital improvements that we expect will increase our asset base, operating capacity or operating income over the long term or meaningfully extend the useful life of any of our capital assets. Examples of expansion capital expenditures include the acquisition of additional assets or businesses, as well as capital projects that improve the service 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. We anticipate funding our proportional share of expansion capital expenditures temporarily through borrowings under our revolving credit facility, with long-term debt and equity funding being obtained when needed and as market conditions allow.

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 June 30, 2014, we had approximately \$85.3 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 \$160.0 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 June 30, 2014, we have recognized approximately \$123.9 million in capital expenditures, including \$28.9 million on maintenance capital activities. For the year ending December 31, 2014, we anticipate our capital expenditures to approximate the following:

	Total Forecasted Expenditures (in millions)
<i>Capital Projects</i>	
Beckville Cryogenic Processing Plant	\$105
Wellconnect Expansion Capital	55
Texas Express NGL system	20
Expansion Capital ⁽¹⁾	105
Maintenance Capital Expenditure Activities	60
<i>Less joint funding from:</i>	
EEP ⁽²⁾	185
	<u>\$160</u>

⁽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.

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 June 30, 2014, for each of the indicated calendar years:

	<u>Notional</u>	<u>2014</u>	<u>2015</u>	<u>2016</u>	<u>2017</u>	<u>2018</u>	<u>Total ⁽³⁾</u>
			(in millions)				
Swaps							
Natural gas ⁽¹⁾	63,567,773	\$(0.7)	\$(0.3)	\$(0.1)	\$—	\$—	\$ (1.1)
NGL ⁽²⁾	2,765,780	(5.2)	(1.0)	—	—	—	(6.2)
Crude Oil ⁽²⁾	1,439,220	(5.8)	(0.3)	0.2	—	—	(5.9)
Options							
Natural gas—puts purchased ⁽¹⁾	7,870,000	0.1	1.0	0.4	—	—	1.5
Natural gas—puts written ⁽¹⁾	3,297,000	(0.1)	(0.6)	—	—	—	(0.7)
Natural gas—calls written ⁽¹⁾	2,924,500	—	(0.2)	(0.3)	—	—	(0.5)
Natural gas—calls purchased ⁽¹⁾	1,277,500	—	0.2	—	—	—	0.2
NGL—puts purchased ⁽²⁾	2,011,650	1.3	4.3	1.3	—	—	6.9
NGL—calls purchased ⁽²⁾	46,000	0.1	—	—	—	—	0.1
NGL—calls written ⁽²⁾	1,034,000	(0.6)	(2.1)	(1.8)	—	—	(4.5)
Crude Oil—puts purchased ⁽²⁾	986,700	—	1.2	1.5	—	—	2.7
Crude Oil—calls written ⁽²⁾	986,700	—	(4.9)	(3.4)	—	—	(8.3)
Forward contracts							
Natural gas ⁽¹⁾	233,150,574	0.5	0.5	0.1	0.1	—	1.2
NGL ⁽²⁾	20,891,067	5.1	1.2	—	—	—	6.3
Crude Oil ⁽²⁾	999,242	(2.3)	—	—	—	—	(2.3)
Totals		<u>\$(7.6)</u>	<u>\$(1.0)</u>	<u>\$(2.1)</u>	<u>\$ 0.1</u>	<u>\$—</u>	<u>\$(10.6)</u>

⁽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 gains at June 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:

	<u>For the six month period ended June 30,</u>		<u>Variance 2014 vs. 2013</u>
	<u>2014</u>	<u>2013</u>	<u>Increase (Decrease)</u>
			(in millions)
Total cash provided by (used in):			
Operating activities	\$176.3	\$ 187.3	\$(11.0)
Investing activities	(71.7)	(262.2)	190.5
Financing activities	126.5	74.9	51.6
Net increase in cash and cash equivalents	231.1	—	231.1
Cash and cash equivalents at beginning of year	4.9	—	4.9
Cash and cash equivalents at end of period	<u>\$236.0</u>	<u>\$ —</u>	<u>\$236.0</u>

Operating Activities

Net cash provided by our operating activities decreased \$11.0 million for the six month period ended June 30, 2014, compared to the same period in 2013, primarily due to a \$59.3 million decrease in net income. This decrease is offset by (1) a \$27.2 million increase in non-cash adjustments, and (2) a \$21.1 increase in our working capital accounts. The primary reason for the increase in our non-cash adjustment was due to increased derivative net losses of \$27.0 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 six month period ended June 30,		Variance 2014 vs. 2013
	2014	2013	
	(in millions)		
Changes in operating assets and liabilities, net of acquisitions:			
Receivables, trade and other	\$ 18.1	\$ (14.1)	\$ 32.2
Due from General Partner and affiliates	622.0	6.4	615.6
Accrued receivables	58.8	276.2	(217.4)
Inventory	(68.1)	(80.8)	12.7
Current and long-term other assets	(5.5)	(1.9)	(3.6)
Due to General Partner and affiliates	(484.2)	(2.4)	(481.8)
Accounts payable and other	(51.5)	(19.0)	(32.5)
Environmental liabilities	0.2	—	0.2
Accrued purchases	1.4	(96.5)	97.9
Interest payable	0.5	—	0.5
Property and other taxes payable	(1.6)	1.1	(2.7)
Net change in working capital accounts	<u>\$ 90.1</u>	<u>\$ 69.0</u>	<u>\$ 21.1</u>

The changes in our operating assets and liabilities, net of acquisitions as presented in our consolidated statements of cash flow for the six month period ended June 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 six month period ended June 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 six month period ended June 30, 2013;
- The decrease in accrued receivables of \$276.2 million from December 31, 2012, to June 30, 2013 was primarily the result of lower production of natural gas and NGLs from our facilities during the six month period ended June 30, 2013. We sold \$133.5 million of our accrued receivables under our Receivables Agreement. For more information, refer to the discussion above *Sale of Accounts Receivable*. The decrease in accrued receivables of \$58.8 million from December 31, 2013, to June 30, 2014, was primarily due to lower prices and volumes of NGLs transported through our trucking and NGL marketing business, partially offset by higher prices and volumes of natural gas and condensate for a net decrease of \$41.8 million. In addition, we sold \$16.2 million more receivables than we incurred for the six month period ended June 30, 2014, through the option to sell our accrued receivables under the Receivables Agreement. For more information, refer to the discussion above in Item 2. *Liquidity and Capital Resources—Sale of Accounts Receivable*; and
- The decline in accrued purchases from December 31, 2012, to June 30, 2013, was primarily the result of lower production of NGLs from our facilities during the month of June 2013 as compared with December 2012 due to some producers electing to retain ethane in the gas stream rather than to extract it.

Investing Activities

Net cash used in our investing activities during the six month period ended June 30, 2014, decreased by \$190.5 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 \$98.6 million since the system went into service in late 2013 offset by \$17.7 million in distributions in excess of cumulative earnings from our joint venture investment in the Texas Express NGL system received during the six month period ended June 30, 2014;
- Decreased additions to property, plant and equipment, net of construction payables of \$27.1 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; and
- Decreased restricted cash balance of \$49.0 million in June 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. For more information, refer to discussion above in Item 2. *Liquidity and Capital Resources—Sale of Accounts Receivable*.

Financing Activities

Net cash provided by our financing activities increased \$51.6 million for the six month period ended June 30, 2014, compared to the same period in 2013, due to:

- Net borrowings of \$140.0 million for amounts previously outstanding under our credit facility in 2014 while we had no debt activity during 2013; and
- Decreased contributions from partners of \$124.6 million partially offset by decreased distributions to partners of \$36.2 million.

SUBSEQUENT EVENTS

Drop Down Acquisition of Additional Interests in Midcoast Operating

On June 18, 2014, we agreed to acquire from EEP a 12.6% limited partner interest in Midcoast Operating for \$350.0 million in cash, which brought our total ownership interest in Midcoast Operating to 51.6%. This transaction closed on July 1, 2014 and 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 financed the transaction entirely with debt through our Credit Agreement.

Purchase of Interest Rate Swaps

On July 2, 2014, we entered into interest rate swaps with a total notional amount of \$200.0 million to hedge future debt issuances for the Partnership. The interest rate swaps have an effective date of December 31, 2014, and a maturity of 5 years.

Distribution to Partners

On July 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 August 14, 2014. The distribution will be paid to unitholders of record as of August 7, 2014, of our available cash of \$15.0 million at June 30, 2014, or \$0.3250 per limited partner unit. We will pay \$6.9 million to our public Class A common unitholders, while \$8.1 million in the aggregate will be paid to EEP with respect to its Class A common units and subordinated units and Midcoast Holdings, with respect to its general partner interest.

Midcoast Operating Distribution

On July 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 August 7, 2014. Midcoast Operating will pay \$23.5 million to us and \$22.0 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 June 30, 2014, and December 31, 2013.

		At June 30, 2014					At December 31, 2013		
		Commodity	Notional ⁽¹⁾	Wtd. Average Price ⁽²⁾		Fair Value ⁽³⁾		Fair Value ⁽³⁾	
				Receive	Pay	Asset	Liability	Asset	Liability
		(in millions)							
Portion of contracts maturing in 2014									
<i>Swaps</i>									
Receive variable/pay fixed	Natural Gas	832,732	\$ 4.41	\$ 4.36	\$ 0.1	\$—	\$—	\$ —	
	NGL	316,000	\$ 62.97	\$ 60.27	\$ 0.9	\$—	\$ 0.6	\$ (0.4)	
Receive fixed/pay variable	Natural Gas	3,631,800	\$ 4.32	\$ 4.42	\$ 0.3	\$(0.7)	\$ 0.1	\$ (1.0)	
	NGL	1,612,280	\$ 54.87	\$ 58.63	\$ 1.0	\$(7.1)	\$ 4.8	\$(12.7)	
	Crude Oil	470,320	\$ 90.89	\$103.18	\$—	\$(5.8)	\$ 0.3	\$ (5.4)	
Receive variable/pay variable . .	Natural Gas	32,675,300	\$ 4.37	\$ 4.38	\$ 0.7	\$(1.1)	\$ 0.6	\$ (0.1)	
<i>Physical Contracts</i>									
Receive variable/pay fixed	Natural Gas	79,594	\$ 4.36	\$ 4.36	\$—	\$—	\$—	\$ —	
	NGL	1,355,000	\$ 35.27	\$ 34.13	\$ 1.6	\$(0.1)	\$ 0.9	\$ (0.9)	
	Crude Oil	81,000	\$105.17	\$107.05	\$—	\$(0.1)	\$—	\$ —	
Receive fixed/pay variable	Natural Gas	333,893	\$ 4.41	\$ 4.40	\$—	\$—	\$—	\$ —	
	NGL	2,403,278	\$ 37.70	\$ 38.51	\$ 0.5	\$(2.5)	\$ 0.4	\$ (2.6)	
	Crude Oil	184,000	\$103.96	\$104.85	\$ 0.2	\$(0.3)	\$—	\$ (0.4)	
Receive variable/pay variable . .	Natural Gas	107,169,373	\$ 4.41	\$ 4.40	\$ 1.3	\$(0.8)	\$ 0.9	\$ (0.4)	
	NGL	13,859,812	\$ 48.43	\$ 48.03	\$ 6.4	\$(0.8)	\$ 5.8	\$ (3.7)	
	Crude Oil	734,242	\$101.94	\$104.89	\$ 0.8	\$(2.9)	\$ 1.1	\$ (1.2)	
Portion of contracts maturing in 2015									
<i>Swaps</i>									
Receive variable/pay fixed	Natural Gas	19,080	\$ 4.47	\$ 4.54	\$—	\$—	\$—	\$ —	
	NGL	82,500	\$ 83.98	\$ 84.84	\$—	\$(0.1)	\$—	\$ —	
	Crude Oil	456,000	\$ 96.90	\$ 92.94	\$ 1.8	\$—	\$—	\$ —	
Receive fixed/pay variable	Natural Gas	596,861	\$ 4.74	\$ 4.51	\$ 0.1	\$—	\$—	\$ —	
	NGL	755,000	\$ 53.11	\$ 54.33	\$ 0.9	\$(1.8)	\$ 1.5	\$ (1.1)	
	Crude Oil	444,650	\$ 92.88	\$ 97.51	\$ 0.3	\$(2.4)	\$ 1.7	\$ —	
Receive variable/pay variable . .	Natural Gas	19,885,000	\$ 4.29	\$ 4.31	\$ 0.3	\$(0.7)	\$ 0.1	\$ —	
<i>Physical Contracts</i>									
Receive fixed/pay variable	NGL	295,624	\$ 53.31	\$ 54.03	\$ 0.1	\$(0.3)	\$—	\$ —	
Receive variable/pay variable . .	Natural Gas	79,446,592	\$ 4.29	\$ 4.29	\$ 1.3	\$(0.8)	\$ 0.5	\$ (0.1)	
	NGL	2,977,353	\$ 66.95	\$ 66.50	\$ 1.9	\$(0.5)	\$—	\$ —	
Portion of contracts maturing in 2016									
<i>Swaps</i>									
Receive fixed/pay variable	Crude Oil	—	\$ —	\$ —	\$—	\$—	\$ 0.7	\$ —	
Receive variable/pay fixed	Crude Oil	68,250	\$ 92.49	\$ 90.00	\$ 0.2	\$—	\$—	\$ —	
Receive variable/pay variable . .	Natural Gas	5,927,000	\$ 4.09	\$ 4.11	\$—	\$(0.1)	\$—	\$ —	
<i>Physical Contracts</i>									
Receive variable/pay variable . .	Natural Gas	32,721,379	\$ 4.16	\$ 4.16	\$ 0.7	\$(0.6)	\$ 0.1	\$ —	
Portion of contracts maturing in 2017									
<i>Physical Contracts</i>									
Receive variable/pay variable . .	Natural Gas	13,399,743	\$ 4.38	\$ 4.36	\$ 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 June 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 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 June 30, 2014, and December 31, 2013.

		At June 30, 2014						At December 31, 2013	
		Commodity	Notional ⁽¹⁾	Strike Price ⁽²⁾	Market Price ⁽²⁾	Fair Value ⁽³⁾		Fair Value ⁽³⁾	
						Asset	Liability	Asset	Liability
		(in millions)							
Portion of option contracts maturing in 2014									
Puts (purchased)	Natural Gas	2,208,000	\$ 3.90	\$ 4.46	\$ 0.1	\$—	\$ 0.7	\$—	
	NGL	386,400	\$54.79	\$56.17	\$ 1.3	\$—	\$ 2.9	\$—	
Calls (written)	NGL	230,000	\$60.92	\$58.65	\$—	\$(0.6)	\$—	\$(1.0)	
Puts (written)	Natural Gas	1,472,000	\$ 3.90	\$ 4.46	\$—	\$(0.1)	\$—	\$(0.5)	
Calls (purchased)	NGL	46,000	\$50.40	\$45.50	\$ 0.1	\$—	\$—	\$—	
Portion of option contracts maturing in 2015									
Puts (purchased)	Natural Gas	4,015,000	\$ 3.90	\$ 4.22	\$ 1.0	\$—	\$ 1.7	\$—	
	NGL	1,259,250	\$49.40	\$54.10	\$ 4.3	\$—	\$ 6.0	\$—	
	Crude Oil	547,500	\$85.42	\$96.40	\$ 1.2	\$—	\$ 1.8	\$—	
Calls (written)	Natural Gas	1,277,500	\$ 5.05	\$ 4.22	\$—	\$(0.2)	\$—	\$(0.3)	
	NGL	438,000	\$57.05	\$54.83	\$—	\$(2.1)	\$—	\$(1.0)	
	Crude Oil	547,500	\$91.75	\$96.40	\$—	\$(4.9)	\$—	\$(1.9)	
Puts (written)	Natural Gas	1,825,000	\$ 4.08	\$ 4.22	\$—	\$(0.6)	\$—	\$—	
Calls (purchased)	Natural Gas	1,277,500	\$ 5.05	\$ 4.22	\$ 0.2	\$—	\$—	\$—	
Portion of option contracts maturing in 2016									
Puts (purchased)	Natural Gas	1,647,000	\$ 3.75	\$ 4.24	\$ 0.4	\$—	\$—	\$—	
	NGL	366,000	\$38.22	\$43.67	\$ 1.3	\$—	\$—	\$—	
	Crude Oil	439,200	\$80.00	\$91.25	\$ 1.5	\$—	\$—	\$—	
Calls (written)	Natural Gas	1,647,000	\$ 4.98	\$ 4.24	\$—	\$(0.3)	\$—	\$—	
	NGL	366,000	\$47.02	\$43.67	\$—	\$(1.8)	\$—	\$—	
	Crude Oil	439,200	\$92.25	\$91.25	\$—	\$(3.4)	\$—	\$—	

⁽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 June 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 gains at June 30, 2014.

Our credit exposure for over-the-counter 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.

	June 30, 2014	December 31, 2013
	(in millions)	
Counterparty Credit Quality ⁽¹⁾		
AAA	\$ 0.2	\$ 0.2
AA	(5.9)	(2.1)
A	(8.0)	(1.1)
Lower than A	3.2	1.6
	<u>\$(10.5)</u>	<u>\$(1.4)</u>

⁽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 June 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 June 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: August 1, 2014

By: /s/ C. Gregory Harper
C. Gregory Harper
Principal Executive Officer

Date: August 1, 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	Purchase and Sale Agreement by and between Enbridge Energy Partners, L.P. and Midcoast Energy Partners, L.P. dated as of June 18, 2014 (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K, filed on June 19, 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.

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: August 1, 2014

By: /s/ C. Gregory Harper

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

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: August 1, 2014

By: /s/ Stephen J. Neyland

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

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 June 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: August 1, 2014

By: /s/ C. Gregory Harper

C. Gregory Harper

Principal Executive Officer

Midcoast Holdings, L.L.C. (as the General Partner)

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 June 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: August 1, 2014

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