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

FORM 10-Q

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

For the quarterly period ended March 31, 2015

OR

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

For the transition period from to

Commission file number 1-36175

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

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

1100 Louisiana Street,
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 May 1, 2015.

MIDCOAST ENERGY PARTNERS, L.P.

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In this report, unless the context otherwise requires, references to "Midcoast Energy Partners," "the Partnership," "MEP," "we," "our," "us," or like terms 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 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 March 31, 2015, we owned a 51.6% controlling interest in Midcoast Operating, and EEP owned a 48.4% noncontrolling interest in Midcoast Operating. Unless otherwise specifically noted, financial results and operating data are shown on a 100% basis and are not adjusted to reflect EEP's 48.4% noncontrolling interest in Midcoast Operating as of March 31, 2015.

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, and the response by natural gas and crude oil producers to changes in any of these factors; (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, 2014, which is available to the public over the Internet at the United States Securities and Exchange Commission's, or the SEC's, website (www.sec.gov) and at our website (www.midcoastpartners.com).

PART I—FINANCIAL INFORMATION

Item 1. Financial Statements

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

	For the three-month period ended March 31, 2015	For the three-month period ended March 31, 2014
	(unaudited; in millions, except per unit amounts)	
Operating revenues:		
Operating revenue (Note 13)	$851.7	$1,589.7
Operating revenue—affiliate (Notes 11 and 13)	21.8	57.2
	873.5	1,646.9
Operating expenses:		
Cost of natural gas and natural gas liquids (Notes 6 and 13)	761.2	1,458.5
Cost of natural gas and natural gas liquids—affiliate (Notes 11 and 13)	17.9	30.2
Operating and maintenance (Notes 7 and 12)	38.2	54.6
Operating and maintenance—affiliate (Note 11)	25.2	27.1
General and administrative	1.9	1.9
General and administrative—affiliate (Note 11)	19.1	25.3
Depreciation and amortization (Note 7)	38.3	37.0
	901.8	1,634.6
Operating income (loss)	(28.3)	12.3
Interest expense, net (Notes 9 and 11)	6.7	3.3
Equity in earnings (loss) of joint ventures (Note 8)	5.7	(1.2)
Other loss (Note 12)	—	(0.1)
Income (loss) before income tax expense	(29.3)	7.7
Income tax expense (Note 14)	0.8	1.0
Net income (loss)	(30.1)	6.7
Less: Net income (loss) attributable to noncontrolling interest	(10.1)	6.3
Net income (loss) attributable to general and limited partner ownership interest in Midcoast Energy Partners, L.P.	$ (20.0)	$ 0.4
Net income (loss) attributable to limited partner ownership interest	$ (19.6)	$ 0.4
Net income (loss) per limited partner unit (basic and diluted) (Note 2)	$ (0.43)	$ 0.01
Weighted average limited partner units outstanding	45.2	45.2

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 March 31,	
	2015	2014
	(unaudited; in millions)	
Net income (loss)	$(30.1)	$6.7
Other comprehensive income (loss), net of tax expense (benefit) of $0.0 million as of March 31, 2015 and 2014 (Note 13)	(2.9)	0.2
Comprehensive income (loss)	(33.0)	6.9
Less: Comprehensive income (loss) attributable to:		
Noncontrolling interest (Note 11)	(10.1)	6.3
Other comprehensive income (loss) attributed to noncontrolling interest (Note 11)	(1.4)	0.2
Comprehensive income (loss) attributable to general and limited partner ownership interests in Midcoast Energy Partners, L.P.	$(21.5)	$0.4

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

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

	For the three-month period ended March 31,	
	2015	2014
	(unaudited; in millions)	
Cash provided by operating activities:		
Net income (loss)	$ (30.1)	$ 6.7
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Depreciation and amortization (Note 7)	38.3	37.0
Derivative fair value net (gains) losses (Note 13)	35.1	(4.6)
Inventory market price adjustments (Note 6)	4.6	1.5
Distributions from investment in joint ventures	5.7	1.6
Equity (earnings) loss from investment in joint ventures (Note 8)	(5.7)	1.3
Other	0.7	1.0
Changes in operating assets and liabilities, net of acquisitions:		
Receivables, trade and other	(11.6)	3.5
Due from General Partner and affiliates	44.4	616.3
Accrued receivables	184.9	59.2
Inventory (Note 6)	48.2	26.2
Current and long-term other assets (Note 13)	(12.1)	(4.8)
Due to General Partner and affiliates	4.8	(478.3)
Accounts payable and other (Notes 5 and 13)	(9.3)	(42.3)
Accrued purchases (Note 12)	(115.9)	(2.4)
Interest payable	(4.1)	0.5
Property and other taxes payable	(9.7)	(8.6)
Net cash provided by operating activities	168.2	213.8
Cash used in investing activities:		
Additions to property, plant and equipment (Notes 7 and 16)	(56.1)	(55.5)
Changes in restricted cash (Note 11)	(2.7)	47.5
Asset acquisitions (Note 3)	(44.1)	—
Investment in joint ventures (Note 8)	(1.9)	(7.3)
Distributions from investment in joint ventures in excess of cumulative earnings	2.4	—
Other	(0.6)	—
Net cash used in investing activities	(103.0)	(15.3)
Cash used in financing activities:		
Net repayments under credit facility (Note 9)	(45.0)	(85.0)
Distributions to partners (Note 10)	(15.8)	(7.7)
Contributions from noncontrolling interest (Note 10)	20.7	39.7
Distributions to noncontrolling interest (Note 10)	(19.8)	(37.4)
Net cash used in financing activities	(59.9)	(90.4)
Net increase in cash and cash equivalents	5.3	108.1
Cash and cash equivalents at beginning of year	—	4.9
Cash and cash equivalents at end of period	$ 5.3	$ 113.0

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

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

	March 31, 2015	December 31, 2014
	(unaudited; in millions)	
ASSETS		
Current assets:		
Cash and cash equivalents (Note 5)	$ 5.3	$ —
Restricted cash (Notes 11 and 13)	63.5	42.8
Receivables, trade and other, net of allowance for doubtful accounts of $1.8 million at March 31, 2015 and December 31, 2014	27.2	15.6
Due from General Partner and affiliates (Note 11)	7.6	49.7
Accrued receivables	44.7	229.6
Inventory (Note 6)	28.7	81.5
Other current assets (Note 13)	158.7	178.1
	335.7	597.3
Property, plant and equipment, net (Note 7)	4,232.4	4,159.7
Goodwill	226.5	226.5
Intangible assets, net	277.9	247.7
Equity investment in joint ventures (Note 8)	380.1	380.6
Other assets, net (Note 13)	127.0	142.3
Total assets	$5,579.6	$5,754.1
LIABILITIES AND PARTNERS' CAPITAL		
Current liabilities:		
Due to General Partner and affiliates (Note 11)	$ 39.6	$ 41.1
Accounts payable and other (Notes 5, 12 and 13)	114.4	113.8
Accrued purchases	253.8	375.2
Property and other taxes payable (Note 14)	11.2	20.9
Interest payable	0.9	5.0
	419.9	556.0
Long-term debt (Note 9)	715.0	760.0
Other long-term liabilities (Notes 12 and 14)	48.5	41.5
Total liabilities	1,183.4	1,357.5
Commitments and contingencies (Note 12)		
Partners' capital (Note 10):		
Class A common units (22,610,056 authorized and issued at March 31, 2015 and December 31, 2014)	616.7	634.2
Subordinated units (22,610,056 authorized and issued at March 31, 2015 and December 31, 2014)	1,156.5	1,174.0
General Partner units (922,859 authorized and issued at March 31, 2015 and December 31, 2014)	47.0	47.8
Accumulated other comprehensive income (Note 13)	10.1	11.6
Total Midcoast Energy Partners, L.P. partners' capital	1,830.3	1,867.6
Noncontrolling interest	2,565.9	2,529.0
Total partners' capital	4,396.2	4,396.6
	$5,579.6	$5,754.1

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

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". For the first six months of 2014, we owned a 39% controlling interest in Midcoast Operating, L.P., or Midcoast Operating. EEP owned the remaining 61% interest in Midcoast Operating. On July 1, 2014, we purchased an additional 12.6% interest in Midcoast Operating from EEP. We own and operate, through our current 51.6% interest in Midcoast Operating, 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. EEP owns a 48.4% noncontrolling interest in Midcoast Operating. EEP also has 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 trade on the New York Stock Exchange, or NYSE, under the ticker symbol MEP.

Basis of Presentation

We have prepared the accompanying unaudited interim consolidated financial statements in accordance with accounting principles generally accepted in the United States, or GAAP, for the interim consolidated financial information and with the instructions to Form 10-Q and Rule 10-01 of Regulation S-X. Accordingly, the unaudited interim consolidated financial statements do not include all the information and notes 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 March 31, 2015, our results of operations for the three-month periods ended March 31, 2015, and 2014, and our cash flows for the three-month periods ended March 31, 2015, and 2014. We derived our consolidated statement of financial position as of December 31, 2014, from the audited financial statements included in our Annual Report on Form 10-K for the fiscal year ended December 31, 2014. Our results of operations for the three-month periods ended March 31, 2015 and 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 notes thereto presented in our Annual Report on Form 10-K for the fiscal year ended December 31, 2014.

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

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

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

	For the three-month period ended March 31,	
	2015	2014
	(in millions, except per unit amounts)	
Net income (loss)	$(30.1)	$ 6.7
Less: Net income (loss) attributable to noncontrolling interest	(10.1)	6.3
Net income (loss) attributable to general and limited partner interests in Midcoast Energy Partners, L.P.	(20.0)	0.4
Less distributions:		
Total distributed earnings to our General Partner	(0.3)	(0.3)
Total distributed earnings to our limited partners	(15.7)	(14.1)
Total distributed earnings	(16.0)	(14.4)
Overdistributed earnings	$(36.0)	$(14.0)
Weighted average limited partner units outstanding	45.2	45.2
Basic and diluted earnings per unit:		
Distributed earnings per limited partner unit (1)	$ 0.35	$ 0.31
Overdistributed earnings per limited partner unit (2)	(0.78)	(0.30)
Net income (loss) per limited partner unit (basic and diluted)	$(0.43)	$ 0.01

(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. ACQUISITIONS

We account for acquisitions using the acquisition method and record the identifiable assets acquired and liabilities assumed at their acquisition-date fair values. We have included the results of operations from this acquisition in our operating results from the acquisition date.

On February 27, 2015, we acquired the midstream business of New Gulf Resources, LLC, or NGR, in Leon, Madison and Grimes counties, Texas for $85.1 million in cash and a contingent future payment of up to $17.0 million. Of the $85.1 million purchase price, $20.0 million was placed into escrow, pending the resolution of a legal matter and NGR's completion of additional wells connecting to our system. During March 2015, $2.0 million was released from escrow and paid to NGR. The remaining $18.0 million in escrow has been classified as "Restricted cash" in our condensed consolidated statement of financial position as of March 31, 2015.

If NGR is able to deliver volumes into the system at certain tiered volume levels over a five-year period, we will be obligated to make future tiered payments up to $17.0 million. This could result in a maximum total purchase price of $102.1 million. The potential payment is considered contingent consideration. The fair value of this contingent consideration, using a probability-weighted discounted cash flow model is $2.3 million. The contingent consideration is presented in "Other long-term liabilities" in our statement of financial position as of March 31, 2015 and will be remeasured on a fair value basis each quarter until the performance bonus is paid or expires.

The acquisition consisted of a natural gas gathering system that is currently in operation moving equity and third party production. Funding was provided by us and EEP based on our proportionate ownership percentages in Midcoast Operating, which are 51.6% and 48.4%, respectively. EEP paid its portion of the funding directly to NGR. Our consolidated statement of cash flows does not reflect the amount paid directly to NGR by EEP.

As of March 31, 2015, the consideration paid and the purchase price allocation related to the NGR acquisition, as adjusted to date, are as follows.

	March 31, 2015
	(in millions)
Consideration:	
Cash consideration	$85.1
Contingent consideration	2.3
	$87.4
Identifiable assets acquired in business combination:	
Property, plant and equipment	$55.1
Intangible assets	32.3
	$87.4

The weighted-average amortization period of intangible assets related to the NGR acquisition is 15 years. Our consolidated operating revenue and net income included $0.1 million and $0.1 million, respectively, from NGR for the three-month period ended March 31, 2015.

Since the effective date of the NGR midstream business acquisition was February 27, 2015, our consolidated statements of income do not include earnings from this business prior to that date. The following table presents selected unaudited pro forma earnings information for the three-month periods ended March 31, 2015 and 2014 as if the acquisition had been completed on January 1, 2014. This pro forma information was prepared using historical financial data for the NGR midstream business and reflects certain estimates and assumptions made by our management based on currently available information. Our unaudited pro forma financial information is not necessarily indicative of what our consolidated financial results would have been for the three-month periods ended March 31, 2015 and 2014 had we acquired the NGR midstream business on January 1, 2014.

	For the three-month period ended March 31,	
	2015	2014
	(unaudited; in millions, except per unit amounts)	
Pro forma earnings data:		
Operating revenue	$873.6	$1,647.2
Operating expenses	$902.2	$1,635.5
Operating income (loss)	$ (28.6)	$ 11.7
Net income (loss)	$ (30.4)	$ 6.1
Net income (loss) attributable to noncontrolling interest	$ (10.2)	$ 5.9
Net income (loss) attributable to limited partner ownership interest	$ (20.2)	$ 0.2
Basic and diluted earnings per unit:		
As reported net income (loss) per limited partner unit (basic and diluted)	$ (0.43)	$ 0.01
Pro forma net income (loss) per limited partner unit (basic and diluted)	$ (0.43)	$ —

4. EQUITY-BASED COMPENSATION

In connection with our initial public offering, or the Offering, our General Partner has adopted the 2013 Midcoast Energy Partners, L.P. Long-Term Incentive Plan, or the LTIP. The LTIP provides for the grant, from time to time at the discretion of the board of directors of our General Partner or any delegate thereof, subject to applicable law, of unit awards, restricted units, phantom units, unit options, unit appreciation rights, distribution equivalent rights and other unit-based awards, provided that while we are an affiliate of Enbridge, awards will only be granted following a recommendation of the board of directors or compensation committee of Enbridge. The purpose of awards under the LTIP is to provide additional incentive compensation to individuals providing services to us, and to align the economic interests of such individuals with the interests of our unitholders.

On February 17, 2015, the Board approved the first Performance Stock Unit, or PSU grants, effective January 1, 2015, under the LTIP. These PSUs were granted to employees of affiliates of our General Partner performing services on our behalf and provide for cash awards to be paid following a three-year performance cycle, at the end of which the units will vest 100%. Awards are calculated by multiplying the number of units outstanding at the end of the performance period by our weighted average share price for the 20 days prior to the maturity of the grant and by a performance multiplier. Any cash distributions paid will be notionally reinvested during the investment cycle.

The performance multiplier ranges from zero, if our performance fails to meet threshold performance levels, to a maximum of two if we perform within the highest range of its performance targets. The 2015 PSU grants derive the performance multiplier through a calculation of our distributable cash flow per unit relative to targets established at the time of grant and yield relative to a specified peer group of companies.

The following table presents PSU activity for the period indicated:

	Performance Stock Units	Weighted Average Remaining Contractual Term (years)	Average Intrinsic Value (in millions)
Outstanding at January 1, 2015	—		
Units granted	323,880		
Units matured	—		
Units forfeited	—		
Dividend reinvested	8,284		
Outstanding at March 31, 2015	332,164	2.8	$4.6

The PSU grants are paid in cash and therefore classified as a liability award. The liability is re-measured at fair value on each reporting date until the award is settled, with the offset for the change in fair value being recorded as compensation expense based on the percentage of the requisite service that has been rendered at the reporting date. During the vesting term, compensation expense is determined based on the number of PSUs outstanding, the current market price of our units, dividends reinvested, and performance multipliers. To calculate the compensation expense for the three-month period ended March 31, 2015, performance multipliers of one, based on estimates as of March 31, 2015, were used for the 2015 PSU grants. The LTIP agreement and the individual award agreements are between our General Partner and the participants in the LTIP agreement. The associated compensation costs and liability are recorded in our consolidated financial statements based on the approved allocation methodology as some of the recipients of our PSU awards provide shared services to us, EEP and other Enbridge entities. Similar to other employee compensation costs, Enbridge Employee Services Incorporated, or EESI, will make the PSU payments to the LTIP participants on behalf of us, EEP and other Enbridge entities who will then reimburse EESI, for their respective obligation, via affiliate payable for the disbursements made to the participants.

As of March 31, 2015, compensation expense recorded for the PSUs was $0.4 million, of which our allocated share of the cost is currently estimated to be $0.1 million. The unrecognized compensation expense related to non-vested units granted was $5.7 million and is expected to be fully recognized over a weighted-average period of approximately three years.

5. 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 $6.9 million at March 31, 2015, and $6.6 million at December 31, 2014, are included in "Accounts payable and other" on our consolidated statements of financial position.

6. INVENTORY

Our inventory is comprised of the following:

	March 31, 2015	December 31, 2014
	(in millions)	
Materials and supplies	$ 0.7	$ 0.7
Crude oil inventory	5.5	2.0
Natural gas and NGL inventory	22.5	78.8
	$28.7	$81.5

The "Cost of natural gas and natural gas liquids" on our consolidated statements of income includes charges totaling $4.6 million and $1.5 million for the three-month periods ended March 31, 2015 and 2014, respectively, that we recorded to reduce the cost basis of our inventory of natural gas and NGLs, to reflect the current market value.

7. PROPERTY, PLANT AND EQUIPMENT

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

	March 31, 2015	December 31, 2014
	(in millions)	
Land	$ 11.3	$ 11.1
Rights-of-way	429.0	405.0
Pipelines	1,845.8	1,785.7
Pumping equipment, buildings and tanks	82.6	82.1
Compressors, meters and other operating equipment	2,096.6	2,074.8
Vehicles, office furniture and equipment	167.6	163.8
Processing and treating plants	533.0	516.0
Construction in progress	199.3	218.7
Total property, plant and equipment	5,365.2	5,257.2
Accumulated depreciation	(1,132.8)	(1,097.5)
Property, plant and equipment, net	$ 4,232.4	$ 4,159.7

8. EQUITY INVESTMENTS IN JOINT VENTURES

We have a 35% aggregate interest in the Texas Express NGL system, which is comprised of two joint ventures with third parties. The Texas Express NGL system consists of a 593-mile NGL intrastate transportation pipeline and a related NGL gathering system. 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 for the Texas Express NGL system on a combined, 100% basis for the periods presented:

	For the three-month period ended March 31,	
	2015	2014
	(in millions)	
Operating revenues	$28.8	$ 5.3
Operating expenses	$11.0	$ 8.4
Net income (loss)	$17.7	$(3.1)

9. DEBT

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

	Interest Rate	March 31, 2015	December 31, 2014
		(in millions)	
Credit Agreement	2.675%	$315.0	$360.0
Series A Senior Notes due 2019	3.560%	75.0	75.0
Series B Senior Notes due 2021	4.040%	175.0	175.0
Series C Senior Notes due 2024	4.420%	150.0	150.0
Total		$715.0	$760.0

Our interest cost for the three-month periods ended March 31, 2015, and 2014, is comprised of the following:

	For the three-month period ended March 31,	
	2015	2014
	(in millions)	
Interest cost incurred	$7.6	$ 3.3
Interest capitalized	0.9	—
Interest expense, net	$6.7	$ 3.3

Debt Arrangements

Credit Agreement

We, Midcoast Operating, and our material domestic subsidiaries are parties to a Credit Agreement, which permits aggregate borrowings of up to, at any one time outstanding, $850.0 million. The original term of the Credit Agreement was three years, with an initial maturity date of November 13, 2016, subject to four one-year requests for extensions. On September 30, 2014, we amended our Credit Agreement to extend the maturity date from November 13, 2016 to September 30, 2017; however, $140.0 million of commitments will expire on the original maturity date of November 13, 2016.

At March 31, 2015, we had $315.0 million in outstanding borrowings under the Credit Agreement at a weighted average interest rate of 2.7%. Under the Credit Agreement, we had net repayments of approximately $45.0 million during the three-month period ended March 31, 2015, which includes gross borrowings of $1,150.0 million and gross repayments of $1,195.0 million. At March 31, 2015, we were in compliance with the terms of our financial covenants in the Credit Agreement.

Senior Notes

Our senior notes in the aggregate amount of $400.0 million were issued in a private placement on September 30, 2014 and consist of three tranches: $75.0 million of 3.56% Series A Senior Notes due in 2019; $175.0 million of 4.04% Series B Senior Notes due in 2021; and $150.0 million of 4.42% Series C Senior Notes due in 2024, collectively the Notes. All of the Notes pay interest semi-annually on March 31 and September 30, commencing on March 31, 2015. At March 31, 2015, we were in compliance with the terms of our financial covenants under the purchase agreement.

Financial Support Agreement

Midcoast Operating is party to a Financial Support Agreement with EEP, pursuant to which EEP provides 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 will incur under the Financial Support Agreement are based on the cumulative average amount of letters of credit and guarantees that EEP will provide on Midcoast Operating's and its wholly owned subsidiaries' behalf multiplied by a 2.5% annual fee. Midcoast Operating incurred $0.2 million of these costs for the three-month period ended March 31, 2015, which is included in "Operating and maintenance-affiliate" on our consolidated statements of income.

Available Credit

At March 31, 2015, we have approximately $535.0 million available under the terms of our Credit Agreement, determined as follows:

	(in millions)
Total credit limit under Credit Agreement	$ 850.0
Amounts outstanding under Credit Agreement	(315.0)
Total amount available at March 31, 2015	$ 535.0

Fair Value of Debt Obligations

The carrying amounts of our outstanding borrowings under the Credit Agreement approximate the fair values at March 31, 2015, and December 31, 2014, respectively, due to the short-term nature and frequent repricing of the amounts outstanding under these obligations. The outstanding borrowings under the Credit Agreement are included with our long-term debt obligations above since we have the ability and the intent to refinance the amounts outstanding on a long-term basis.

The approximate fair values of our fixed-rate debt obligations were $391.9 million at March 31, 2015. We determined the approximate fair values using a standard methodology that incorporates pricing points that are obtained from independent, third-party investment dealers who actively make markets in our debt securities. We use these pricing points to calculate the present value of the principal obligation to be repaid at maturity and all future interest payment obligations for any debt outstanding. The fair value of our long-term debt obligations is categorized as Level 2 within the fair value hierarchy.

10. PARTNERS' CAPITAL

Distribution to Partners

The following table sets forth our distributions, as approved by the board of directors of our General Partner, during the three-month period ended March 31, 2015.

Distribution Declaration Date	Record Date	Distribution Payment Date	Distribution per Unit	Cash Distributed
			(in millions, except per unit amounts)	
January 28, 2015	February 6, 2015	February 13, 2015	$0.34250	$15.8

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 three-month period ended March 31, 2015 and 2014.

	For the three-month period ended March 31, 2015	2014
	(in millions)	
Class A common units:		
Beginning balance	$ 634.2	$ 495.3
Net income (loss)	(9.8)	0.2
Distributions	(7.7)	(3.7)
Ending balance	$ 616.7	$ 491.8
Subordinated units:		
Beginning balance	$1,174.0	$1,035.1
Net income (loss)	(9.8)	0.2
Distributions	(7.7)	(3.8)
Ending balance	$1,156.5	$1,031.5
General Partner units:		
Beginning balance	$ 47.8	$ 42.2
Net loss	(0.4)	(0.2)
Distributions	(0.4)	—
Ending balance	$ 47.0	$ 42.0
Accumulated other comprehensive income (loss)		
Beginning balance	$ 11.6	$ (3.1)
Changes in fair value of derivative financial instruments reclassified to earnings	(4.3)	6.5
Changes in fair value of derivative financial instruments recognized in other comprehensive income (loss)	2.8	(6.3)
Ending balance	$ 10.1	$ (2.9)
Noncontrolling interest		
Beginning balance	$2,529.0	$2,983.2
Capital contributions	68.2	46.1
Comprehensive income:		
Net income (loss)	(10.1)	6.3
Other comprehensive income (loss), net of tax	(1.4)	0.2
Distributions to noncontrolling interest	(19.8)	(37.4)
Ending balance	$2,565.9	$2,998.4
Total partners' capital at end of period	$4,396.2	$4,560.8

Securities Authorized for Issuance under Equity Compensation Plans

In connection with our LTIP, we filed a registration statement on Form S-8 with the SEC registering the issuance of 3,750,000 Class A common units that are issuable pursuant to awards granted under the LTIP. As of March 31, 2015, we have not issued any Class A common units under our LTIP.

Shelf-Registration Statement

From time to time, we may seek to satisfy liquidity needs through the issuance of registered debt or equity securities. To that end, in December 2014, we filed a shelf registration statement on Form S-3 with the SEC with a proposed aggregate offering price for all securities registered of $1.5 billion, which became effective on February 5, 2015.

11. RELATED PARTY TRANSACTIONS

Intercorporate Services Agreement

We do not directly employ any of the individuals responsible for managing or operating our business nor do we have any directors. We have an Intercorporate Services Agreement with EEP, pursuant to which EEP and its affiliates provides us with services as set forth in the agreement, which include such functions as management, accounting, operational and administrative personnel, among other such functions.

Under the Intercorporate Services Agreement, we reimburse EEP and its affiliates for the costs and expenses incurred in providing us with such services. The affiliate amounts incurred by us through EEP for services received pursuant to the Intercorporate Services Agreement are reflected in “Operating and maintenance—affiliate” and “General and administrative—affiliate” on our consolidated statements of income. EEP has agreed to reduce the amounts payable for general and administrative expenses that otherwise would have been allocable to Midcoast Operating by $25.0 million annually. As a result, for the three-month period ended March 31, 2015, we recognized $6.3 million as a reduction to “Due to General Partner and affiliates” with the offset recorded as a contribution to “Noncontrolling interest” in our consolidated statements of financial position.

Enbridge and Enbridge Management and their respective affiliates allocated direct workforce costs to us for our construction projects of $0.5 million and $5.8 million as of March 31, 2015, and December 31, 2014, respectively, that we recorded as additions to “Property, plant and equipment, net” on our consolidated statements of financial position.

Affiliate Revenues and Purchases

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

Also, included in “Cost of natural gas and natural gas liquids—affiliate”, for the three-month periods ended March 31, 2015 and 2014, are $5.8 million and $5.3 million, respectively, of pipeline transportation and demand fees from Texas Express NGL system. 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 2015 to 2022.

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-month periods ended March 31, 2015 and 2014. 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.

Partners' Capital Transactions

Midcoast Operating paid cash distributions totaling $19.8 million and $37.4 million to EEP during the three-month periods ended March 31, 2015 and 2014, respectively, for its ownership interest in Midcoast Operating. In addition, we paid cash distributions totaling $8.5 million and $4.1 million to EEP for the three-month periods ended March 31, 2015 and 2014, respectively, for its ownership interest in us. These amounts are reflected in "Distributions to noncontrolling interest" and "Distributions to partners", respectively, on our consolidated statements of cash flows.

Sale of Accounts Receivable

For the three-month periods ended March 31, 2015 and 2014, we sold and derecognized $705.4 million and $976.3 million, respectively, of receivables to an indirect wholly-owned subsidiary of Enbridge. For the three-month periods ended March 31, 2015 and 2014, we received cash proceeds of $705.2 million and $976.0 million, respectively. As of March 31, 2015 and December 31, 2014, $242.5 million and $272.7 million, respectively, of the receivables were outstanding and had not been collected on behalf of the Enbridge subsidiary.

Consideration for the receivables sold is equivalent to the carrying value of the receivables less a discount for credit risk. The difference between the carrying value of the receivables sold and the cash proceeds received is recognized in "General and administrative—affiliate" expense in our consolidated statements of income. For the three-month periods ended March 31, 2015 and 2014, the expense stemming from the discount on the receivables sold was $0.2 million and $0.3 million, respectively.

As of March 31, 2015 and December 31, 2014, we had $22.9 million and $17.7 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.

12. 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 March 31, 2015, we did not have any remaining material accrued environmental liabilities. As of December 31, 2014, we had $0.2 million of accrued environmental liabilities included in "Other long-term 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 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.

13. 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 the variability in future cash flows associated with commodity price risks through 2020 in accordance with our risk management policies. Our derivative instruments that qualify for hedge accounting under authoritative guidance are classified as cash flow hedges.

Derivative Positions

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

	March 31, 2015	December 31, 2014
	(in millions)	
Other current assets	$133.5	$164.7
Other assets, net	76.4	91.5
Accounts payable and other [(1)]	(61.7)	(74.4)
Other long-term liabilities	(21.0)	(22.5)
Due from General Partner and affiliates	0.1	0.3
	$127.3	$159.6

(1) Includes $22.6 million and $28.4 million of cash collateral at March 31, 2015 and December 31, 2014, respectively.

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

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

	March 31, 2015	December 31, 2014
	(in millions)	
Counterparty Credit Quality [(1)]		
AAA	$ 0.4	$ 0.1
AA [(2)]	69.5	74.4
A	47.4	67.1
Lower than A	10.0	18.0
	$127.3	$159.6

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

(2) Includes $22.6 million and $28.4 million of cash collateral at March 31, 2015 and December 31, 2014, respectively.

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 March 31, 2015, and December 31, 2014, we were holding cash collateral of $22.6 million and $28.4 million on our asset exposures, respectively. Cash collateral is classified as "Restricted cash" in our consolidated statements of financial position. 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.

The ISDA® agreements and associated credit support, which govern our financial derivative transactions, contain no credit rating downgrade triggers that would accelerate the maturity dates of our outstanding transactions. A change in ratings is not an event of default under these instruments, and the maintenance of a specific minimum credit rating is not a condition to transacting under the ISDA® agreements. In the event of a credit downgrade, additional collateral may be required to be posted under the agreement if we are in a liability position to our counterparty, but the agreement will not automatically terminate and require immediate settlement of all future amounts due.

The ISDA® agreements, in combination with our master netting agreements, and credit arrangements governing our commodity swaps require that collateral be posted per tiered contractual thresholds based on the credit rating of each counterparty. We generally provide letters of credit to satisfy such collateral requirements under our ISDA® agreements. These agreements will require additional collateral postings of up to 100% on net liability positions in the event of a credit downgrade below investment grade. Automatic termination clauses which exist are related only to non-performance activities, such as the refusal to post collateral when contractually required to do so. When we are holding an asset position, our counterparties are likewise required to post collateral on their liability (our asset) exposures, also determined by tiered contractual collateral thresholds. Counterparty collateral may consist of cash or letters of credit, both of which must be fulfilled with immediately available funds.

At March 31, 2015, and December 31, 2014, we had credit concentrations in the following industry sectors, as presented below:

	March 31, 2015	December 31, 2014
	(in millions)	
United States financial institutions and investment banking entities [1]	$ 80.3	$ 88.5
Non-United States financial institutions	19.0	30.7
Integrated oil companies	0.1	1.7
Other	27.9	38.7
	$127.3	$159.6

(1) Includes $22.6 million and $28.4 million of cash collateral at March 31, 2015 and December 31, 2014, respectively.

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

Effect of Derivative Instruments on the Consolidated Statements of Financial Position

	Financial Position Location	Asset Derivatives Fair Value at March 31, 2015	Asset Derivatives Fair Value at December 31, 2014	Liability Derivatives Fair Value at March 31, 2015	Liability Derivatives Fair Value at December 31, 2014
		(in millions)			
Derivatives designated as cash flow hedging instruments [1]					
Commodity contracts	Other current assets	$ 20.7	$ 26.1	$ —	$ —
Commodity contracts	Other assets	—	2.1	—	—
		20.7	28.2	—	—
Derivatives not designated as hedging instruments					
Commodity contracts	Other current assets	112.8	138.6	—	—
Commodity contracts	Other assets	76.4	89.4	—	—
Commodity contracts	Accounts payable and other [2]	—	—	(39.1)	(46.0)
Commodity contracts	Other long-term liabilities	—	—	(21.0)	(22.5)
Commodity contracts	Due from general partner and affiliates	0.1	0.3	—	—
		189.3	228.3	(60.1)	(68.5)
Total derivative instruments		$210.0	$256.5	$(60.1)	$(68.5)

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

(2) Excludes total of $22.6 million and $28.4 million of cash collateral at March 31, 2015 and December 31, 2014, respectively.

Accumulated Other Comprehensive Income

Also included in AOCI, as of March 31, 2015, are unrecognized gains of approximately $0.5 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 three-month periods ended March 31, 2015 and 2014, unrealized commodity hedge gains of $0.6 million and losses of $0.1 million, respectively, were de-designated as a result of the hedges no longer meeting hedge accounting criteria. We estimate that approximately $21.7 million, representing unrealized net gains from our cash flow hedging activities based on pricing and positions at March 31, 2015, will be reclassified from AOCI to earnings during the next 12 months.

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 March 31, 2015					
Commodity contracts	$(3.6)	Cost of natural gas and natural gas liquids	$ 8.4	Cost of natural gas and natural gas liquids	$(4.0)
For the three-month period ended March 31, 2014					
Commodity contracts	$(0.1)	Cost of natural gas and natural gas liquids	$(6.5)	Cost of natural gas and natural gas liquids	$ 1.7

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

Components of Accumulated Other Comprehensive Income/(Loss)

	Cash Flow Hedges 2015	Cash Flow Hedges 2014
	(in millions)	
Balance at January 1,	$11.6	$(3.1)
Other Comprehensive Income before reclassifications [1]	2.8	(2.4)
Amounts reclassified from AOCI [2] [3]	(4.3)	2.6
Net other comprehensive loss	$ (1.5)	$ 0.2
Balance at March 31,	$10.1	$(2.9)

(1) Excludes NCI gain of $2.7 million and loss of $3.7 million reclassified from AOCI at March 31, 2015 and 2014, respectively.

(2) Excludes NCI loss of $4.1 million and gain of $3.9 million reclassified from AOCI at March 31, 2015 and 2014, respectively.

(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 March 31, 2015	For the three-month period ended March 31, 2014
	(in millions)	
Losses (gains) on cash flow hedges:		
Commodity Contracts [1] [2]	$(4.3)	$2.6
Total Reclassifications from AOCI	$(4.3)	$2.6

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

(2) Excludes NCI loss of $4.1 million and NCI gain of $3.9 million reclassified from AOCI for the three-month periods ended March 31, 2015 and 2014, respectively.

Effect of Derivative Instruments on Consolidated Statements of Income

Derivatives Not Designated as Hedging Instruments	Location of Gain or (Loss) Recognized in Earnings [1]	Amount of Gain or (Loss) Recognized in Earnings [2] — For the three-month period ended March 31, 2015	2014
		(in millions)	
Commodity contracts	Operating revenue	$(17.3)	$ 0.8
Commodity contracts	Operating revenue — affiliate	(0.2)	—
Commodity contracts	Cost of natural gas and natural gas liquids [3]	12.1	(6.4)
Total		$ (5.4)	$(5.6)

(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 $25.7 million and ($8.5) million for the three-month periods ended March 31, 2015 and 2014, respectively.

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 March 31, 2015				
	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 (1)	Net Amount
			(in millions)		
Description:					
Derivatives	$210.0	$—	$210.0	$(76.5)	$133.5

	As of December 31, 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 (1)	Net Amount
			(in millions)		
Description:					
Derivatives	$256.5	$—	$256.5	$(91.8)	$164.7

(1) Includes $22.6 million and $28.4 million of cash collateral at March 31, 2015 and December 31, 2014, respectively.

Offsetting of Financial Liabilities and Derivative Liabilities

	As of March 31, 2015				
	Gross Amount of Recognized Liabilities (1)	Gross Amount Offset in the Statement of Financial Position	Net Amount of Liabilities Presented in the Statement of Financial Position	Gross Amount Not Offset in the Statement of Financial Position (1)	Net Amount
			(in millions)		
Description:					
Derivatives	$(82.7)	$—	$(82.7)	$76.5	$(6.2)

	As of December 31, 2014				
	Gross Amount of Recognized Liabilities (1)	Gross Amount Offset in the Statement of Financial Position	Net Amount of Liabilities Presented in the Statement of Financial Position	Gross Amount Not Offset in the Statement of Financial Position (1)	Net Amount
			(in millions)		
Description:					
Derivatives	$(96.9)	$—	$(96.9)	$91.8	$(5.1)

(1) Includes $22.6 million and $28.4 million of cash collateral at March 31, 2015 and December 31, 2014, respectively.

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 March 31, 2015, and December 31, 2014. 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.

	March 31, 2015					December 31, 2014				
	Level 1	Level 2	Level 3	Collateral	Total	Level 1	Level 2	Level 3	Collateral	Total
	(in millions)									
Commodity contracts:										
Financial	$—	$13.1	$ 30.3	$ —	$ 43.4	$—	$19.1	$ 42.7	$ —	$ 61.8
Physical	—	—	7.0	—	7.0	—	—	19.5	—	19.5
Commodity options	—	—	99.5	—	99.5	—	—	106.7	—	106.7
	$—	$13.1	$136.8	$ —	$149.9	$—	$19.1	$168.9	$ —	$188.0
Cash Collateral	—	—	—	(22.6)	(22.6)	—	—	—	(28.4)	(28.4)
Total	$—	$13.1	$136.8	$(22.6)	$127.3	$—	$19.1	$168.9	$(28.4)	$159.6

Qualitative Information about Level 2 Fair Value Measurements

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

Qualitative Information about Level 3 Fair Value Measurements

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

Quantitative Information About Level 3 Fair Value Measurements

Contract Type	Fair Value at[2] March 31, 2015	Valuation Technique	Unobservable Input	Range[1] Lowest	Highest	Weighted Average	Units
	(in millions)						
Commodity Contracts—Financial							
Natural Gas	$ 1.6	Market Approach	Forward Gas Price	2.23	3.56	2.79	MMBtu
NGLs	$ 28.7	Market Approach	Forward NGL Price	0.18	1.14	0.63	Gal
Commodity Contracts—Physical							
Natural Gas	$ 1.9	Market Approach	Forward Gas Price	2.23	4.24	2.69	MMBtu
Crude Oil	$ (0.7)	Market Approach	Forward Crude Oil Price	38.21	53.70	48.97	Bbl
NGLs	$ 5.8	Market Approach	Forward NGL Price	0.08	1.40	0.43	Gal
Commodity Options							
Natural Gas, Crude and NGLs	$ 99.5	Option Model	Option Volatility	18%	112%	33%	
Total Fair Value	$136.8						

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

(2) Fair values are presented in millions of dollars and include credit valuation adjustments of approximately $0.8 million of losses.

Quantitative Information About Level 3 Fair Value Measurements

Contract Type	Fair Value at December 31, 2014[2]	Valuation Technique	Unobservable Input	Range[1] Lowest	Highest	Weighted Average	Units
	(in millions)						
Commodity Contracts—Financial							
Natural Gas	$ 0.6	Market Approach	Forward Gas Price	2.55	3.72	3.04	MMBtu
NGLs	$ 42.1	Market Approach	Forward NGL Price	0.48	1.14	0.64	Gal
Commodity Contracts—Physical							
Natural Gas	$ 1.5	Market Approach	Forward Gas Price	1.55	4.08	3.08	MMBtu
Crude Oil	$ (0.9)	Market Approach	Forward Crude Oil Price	49.57	55.60	53.51	Bbl
NGLs	$ 18.9	Market Approach	Forward NGL Price	0.06	1.21	0.54	Gal
Commodity Options							
Natural Gas, Crude and NGLs	$106.7	Option Model	Option Volatility	19%	94%	36%	
Total Fair Value	$168.9						

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

(2) Fair values include credit valuation adjustments of approximately $1.0 million of losses.

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, 2015 to March 31, 2015. 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, 2015	$ 42.7	$ 19.5	$106.7	$168.9
Transfer out of Level 3 [1]	—	—	—	—
Gains or losses included in earnings:				
Reported in Operating revenue	—	1.5	—	1.5
Reported in Cost of natural gas and natural gas liquids	0.2	4.9	4.0	9.1
Gains or losses included in other comprehensive income:				
Reported in Other comprehensive income (loss), net of tax	(1.4)	—	—	(1.4)
Purchases, issuances, sales and settlements:				
Purchases	—	—	—	—
Sales	—	—	—	—
Settlements [2]	(11.2)	(18.9)	(11.2)	(41.3)
Ending balance as of March 31, 2015	$ 30.3	$ 7.0	$ 99.5	$136.8
Amounts reported in Operating revenue	$ —	$(17.5)	$ —	$ (17.5)
Amount of changes in net assets attributable to the change in unrealized gains or losses related to assets and liabilities still held at the reporting date:				
Reported in Operating revenue	$ —	$ 2.6	$ —	$ 2.6
Reported in Cost of natural gas and natural gas liquids	$ 2.2	$ 3.1	$ 7.7	$ 13.0

(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 March 31, 2015 and December 31, 2014.

	At March 31, 2015						At December 31, 2014	
			Wtd. Average Price [2]		Fair Value [3]		Fair Value [3]	
	Commodity	Notional [1]	Receive	Pay	Asset	Liability	Asset	Liability
						(in millions)		
Portion of contracts maturing in 2015								
Swaps								
Receive variable/pay fixed	Natural Gas	1,541,324	$ 2.61	$ 2.98	$ —	$ (0.6)	$ —	$ (0.7)
	NGL	504,250	$33.12	$40.52	$ 0.1	$ (3.8)	$ —	$ (6.8)
	Crude Oil	739,750	$52.35	$83.30	$ —	$(22.9)	$ —	$(27.4)
Receive fixed/pay variable	Natural Gas	1,728,938	$ 2.91	$ 2.71	$ 0.4	$ —	$ 3.7	$ —
	NGL	1,550,500	$46.19	$31.00	$24.0	$ (0.5)	$39.2	$ —
	Crude Oil	915,000	$90.93	$52.62	$35.0	$ —	$42.4	$ —
Receive variable/pay variable	Natural Gas	68,310,000	$ 2.56	$ 2.54	$ 2.6	$ (1.5)	$ 1.5	$ (1.7)
Physical Contracts								
Receive variable/pay fixed	Natural Gas	155,150	$ 2.39	$ 2.19	$ —	$ —	$ —	$ —
	NGL	80,000	$32.76	$41.89	$ —	$ (0.7)	$ —	$ (3.6)
	Crude Oil	11,000	$48.18	$51.64	$ —	$ —	$ —	$ —
Receive fixed/pay variable	Natural Gas	406,373	$ 2.46	$ 2.51	$ —	$ —	$ —	$ —
	NGL	398,525	$26.68	$21.93	$ 1.9	$ (0.1)	$19.8	$ —
	Crude Oil	109,000	$52.59	$50.02	$ 0.3	$ —	$ 0.5	$ —
Receive variable/pay variable	Natural Gas	192,448,455	$ 2.61	$ 2.61	$ 1.6	$ (0.5)	$ 2.2	$ (1.0)
	NGL	10,861,860	$18.50	$18.15	$ 3.9	$ (0.1)	$ 3.7	$ (1.0)
	Crude Oil	654,682	$46.53	$47.97	$ 1.0	$ (1.9)	$ 0.3	$ (1.7)
Portion of contracts maturing in 2016								
Swaps								
Receive variable/pay fixed	Natural Gas	363,514	$ 2.75	$ 3.41	$ —	$ (0.2)	$ —	$ (0.1)
	Crude Oil	415,950	$58.02	$82.69	$ —	$(10.2)	$ —	$ (8.1)
Receive fixed/pay variable	Natural Gas	465,600	$ 3.32	$ 3.16	$ 0.1	$ —	$ —	$ —
	NGL	823,500	$39.64	$27.63	$ 9.8	$ —	$ 9.3	$ —
	Crude Oil	415,950	$85.08	$58.02	$11.2	$ —	$ 9.1	$ —
Receive variable/pay variable	Natural Gas	44,959,000	$ 2.93	$ 2.91	$ 2.0	$ (1.1)	$ 0.5	$ (0.3)
Physical Contracts								
Receive fixed/pay variable	Natural Gas	63,591	$ 3.12	$ 2.98	$ —	$ —	$ —	$ —
	NGL	4,398	$29.86	$25.91	$ —	$ —	$ —	$ —
Receive variable/pay variable	Natural Gas	59,944,568	$ 3.05	$ 3.04	$ 0.9	$ (0.4)	$ 0.7	$ (0.4)
	NGL	8,944,071	$18.00	$17.89	$ 0.9	$ —	$ —	$ —
Portion of contracts maturing in 2017								
Swaps								
Receive variable/pay fixed	Natural Gas	24,030	$ 3.24	$ 3.48	$ —	$ —	$ —	$ —
	NGL	547,500	$23.81	$25.86	$ —	$ (1.1)	$ —	$ —
	Crude Oil	547,500	$61.30	$66.72	$ —	$ (2.9)	$ —	$ —
Receive fixed/pay variable	NGL	547,500	$23.59	$23.81	$ 0.3	$ (0.5)	$ 0.7	$ —
	Crude Oil	547,500	$66.78	$61.30	$ 2.9	$ —	$ 0.8	$ —
Receive variable/pay variable	Natural Gas	2,700,000	$ 3.44	$ 3.37	$ 0.2	$ —	$ —	$ —
Physical Contracts								
Receive variable/pay variable	Natural Gas	28,047,550	$ 3.36	$ 3.35	$ 0.3	$ (0.1)	$ 0.2	$ (0.1)
Portion of contracts maturing in 2018								
Physical Contracts								
Receive variable/pay variable	Natural Gas	5,787,810	$ 3.57	$ 3.56	$ 0.1	$ —	$ —	$ —
Portion of contracts maturing in 2019								
Physical Contracts								
Receive variable/pay variable	Natural Gas	2,187,810	$ 3.56	$ 3.53	$ 0.1	$ —	$ —	$ —
Portion of contracts maturing in 2020								
Physical Contracts								
Receive variable/pay variable	Natural Gas	359,640	$ 3.88	$ 3.85	$ —	$ —	$ —	$ —

(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 March 31, 2015, and December 31, 2014, respectively, discounted using the swap rate for the respective periods to consider the time value of money. Fair values are presented in millions of dollars and exclude credit valuation adjustments of approximately $0.1 million of losses at March 31, 2015 and $0.4 million of losses at December 31, 2014, as well as cash collateral received.

The following table provides summarized information about the fair value of expected cash flows of our outstanding commodity options at March 31, 2015 and December 31, 2014.

	At March 31, 2015						At December 31, 2014	
					Fair Value [3]		Fair Value [3]	
	Commodity	Notional [1]	Strike Price [2]	Market Price [2]	Asset	Liability	Asset	Liability
						(in millions)		
Portion of option contracts maturing in 2015								
Puts (purchased) . . .	Natural Gas	3,025,000	$ 3.90	$ 2.78	$ 3.5	$—	$ 3.8	$—
	NGL	1,732,500	$43.32	$26.68	$29.3	$—	$40.2	$—
	Crude Oil	550,000	$81.56	$52.55	$16.0	$—	$18.8	$—
Calls (written)	Natural Gas	962,500	$ 5.05	$ 2.78	$ —	$—	$ —	$—
	NGL	1,113,750	$45.80	$26.06	$ —	$(0.2)	$ —	$(0.6)
	Crude Oil	550,000	$88.39	$52.55	$ —	$—	$ —	$(0.4)
Puts (written)	Natural Gas	3,025,000	$ 3.90	$ 2.79	$ —	$(3.5)	$ —	$(3.8)
Calls (purchased) . .	Natural Gas	962,500	$ 5.05	$ 2.78	$ —	$—	$ —	$—
Portion of option contracts maturing in 2016								
Puts (purchased) . . .	Natural Gas	1,647,000	$ 3.75	$ 3.11	$ 1.3	$—	$ 1.0	$—
	NGL	2,836,500	$39.24	$26.46	$39.9	$—	$39.3	$—
	Crude Oil	805,200	$75.91	$58.23	$15.6	$—	$14.7	$—
Calls (written)	Natural Gas	1,647,000	$ 4.98	$ 3.11	$ —	$(0.1)	$ —	$(0.1)
	NGL	2,836,500	$45.14	$26.46	$ —	$(2.4)	$ —	$(3.2)
	Crude Oil	805,200	$86.68	$58.23	$ —	$(0.5)	$ —	$(2.7)
Puts (written)	Natural Gas	1,647,000	$ 3.75	$ 3.11	$ —	$(1.3)	$ —	$(1.0)
Calls (purchased) . .	Natural Gas	1,647,000	$ 4.98	$ 3.11	$ 0.1	$—	$ 0.1	$—
Portion of option contracts maturing in 2017								
Puts (purchased) . . .	NGL	547,500	$21.70	$23.81	$ 1.0	$—	$ 1.2	$—
	Crude Oil	547,500	$63.00	$61.30	$ 5.1	$—	$ 4.1	$—
Calls (written)	NGL	547,500	$25.34	$23.81	$ —	$(1.2)	$ —	$(0.7)
	Crude Oil	547,500	$71.45	$61.30	$ —	$(2.5)	$ —	$(3.3)

(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 March 31, 2015, and December 31, 2014, respectively, discounted using the swap rate for the respective periods to consider the time value of money. Fair values are presented in millions of dollars and exclude any credit valuation adjustments of approximately $0.6 million and $0.7 million of losses at March 31, 2015 and December 31, 2014, respectively, as well as cash collateral received.

14. 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 0.6% and 0.5% for the three-month periods ended March 31, 2015 and 2014, respectively. Our income tax expense is $0.8 million and $1.0 million for the three-month periods ended March 31, 2015 and 2014, respectively.

At March 31, 2015 and December 31, 2014, we included a current income tax payable of $2.1 million and $1.5 million, respectively, in “Property and other taxes payable” on our consolidated statements of financial position. In addition, at March 31, 2015 and December 31, 2014, we included a deferred income tax payable of $14.4 million and $14.2 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.

15. 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 are 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:

	As of and for the three-month period ended March 31, 2015			
	Gathering, Processing and Transportation	Logistics and Marketing	Corporate [1]	Total
	(in millions)			
Total revenue	$ 385.4	$765.3	$ —	$1,150.7
Less: Intersegment revenue	267.3	9.9	—	277.2
Operating revenue	118.1	755.4	—	873.5
Cost of natural gas and natural gas liquids	21.9	757.2	—	779.1
Segment gross margin	96.2	(1.8)	—	94.4
Operating and maintenance	50.8	12.6	—	63.4
General and administrative	16.3	3.0	1.7	21.0
Depreciation and amortization	36.7	1.6	—	38.3
	103.8	17.2	1.7	122.7
Operating loss	(7.6)	(19.0)	(1.7)	(28.3)
Interest expense, net	—	—	6.7	6.7
Other income	5.7 [2]	—	—	5.7
Loss before income tax expense	(1.9)	(19.0)	(8.4)	(29.3)
Income tax expense	—	—	0.8	0.8
Net loss	(1.9)	(19.0)	(9.2)	(30.1)
Less: Net loss attributable to:				
Noncontrolling interest	—	—	(10.1)	(10.1)
Net income (loss) attributable to general and limited partner ownership interests in Midcoast Energy Partners, L.P.	$ (1.9)	$ (19.0)	$ 0.9	$ (20.0)
Total assets	$5,226.2 [3]	$236.9	$116.5	$5,579.6
Capital expenditures (excluding acquisitions)	$ 54.8	$ 0.7	$ 0.1	$ 55.6

(1) Corporate consists of interest expense, interest income, noncontrolling interest and other costs such as income taxes, 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.

(3) Totals assets for our Gathering, Processing and Transportation segment includes $380.1 million for our long-term equity investment in the Texas Express NGL system.

	As of and for the three-month period ended March 31, 2014			
	Gathering, Processing and Transportation	Logistics and Marketing	Corporate [1]	Total
	(in millions)			
Total revenue	$ 725.0	$1,473.0	$ —	$2,198.0
Less: Intersegment revenue	521.7	29.4	—	551.1
Operating revenue	203.3	1,443.6	—	1,646.9
Cost of natural gas and natural gas liquids	84.8	1,403.9	—	1,488.7
Segment gross margin	118.5	39.7	—	158.2
Operating and maintenance	64.4	17.3	—	81.7
General and administrative	24.0	3.2	—	27.2
Depreciation and amortization	35.0	2.0	—	37.0
	123.4	22.5	—	145.9
Operating income (loss)	(4.9)	17.2	—	12.3
Interest expense, net	—	—	3.3	3.3
Other expense	(1.2) [2]	—	(0.1)	(1.3)
Income (loss) before income tax expense	(6.1)	17.2	(3.4)	7.7
Income tax expense	—	—	1.0	1.0
Net income (loss)	(6.1)	17.2	(4.4)	6.7
Less: Net income attributable to:				
Noncontrolling interest	—	—	6.3	6.3
Net income (loss) attributable to general and limited partner ownership interests in Midcoast Energy Partners, L.P.	$ (6.1)	$ 17.2	$ (10.7)	$ 0.4
Total assets	$4,901.7 [3]	$ 311.1	$216.7	$5,429.5
Capital expenditures (excluding acquisitions)	$ 47.8	$ 2.3	$ 5.3	$ 55.4

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

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

(3) Totals assets for our Gathering, Processing and Transportation segment includes $375.7 million for our long-term equity investment in the Texas Express NGL system.

16. SUPPLEMENTAL CASH FLOW INFORMATION

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

	For the three-month period ended March 31,	
	2015	2014
	(in millions)	
Additions to property, plant and equipment	$56.1	$55.5
Decrease in construction payables	(0.5)	(0.1)
Total capital expenditures (excluding "Investment in joint ventures")	$55.6	$55.4

17. RECENT ACCOUNTING PRONOUNCEMENTS NOT YET ADOPTED

Revenues from Contracts with Customers

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

Going Concern Uncertainties

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

Consolidation

In February 2015, the FASB issued Accounting Standards Update No. 2015-02, which addresses concerns about the current accounting for consolidation of certain legal entities. It makes targeted amendments to the current consolidations guidance and ends the deferral granted to certain entities from applying the variable interest entity, or VIE guidance. Among other things, the amended standard eliminates the specialized consolidation model and guidance for limited partnerships, which included the presumption that the general partner should consolidate a limited partnership. This accounting update is effective for annual and interim periods beginning after December 15, 2015. Early adoption is permitted, and the new standard may be adopted either retrospectively or using a modified retrospective approach. We are currently evaluating which transition approach we will apply and the impact that this pronouncement will have on our consolidated financial statements, though we expect that this amended guidance will require us to (1) revisit our consolidation model and perform a VIE analysis for each limited partnership that we currently consolidate and (2) include additional disclosures within our consolidated financial statements.

Debt Issuance Costs

In April 2015, the FASB issued Accounting Standards Update No. 2015-03, which simplifies the presentation of debt issuance costs. The standard requires that debt issuance costs related to a recognized debt liability be presented in the balance sheet as a direct deduction from the carrying amount of that debt liability, and that the amortization of the debt issuance cost should be recorded as interest expense. The amendments do not affect the current guidance on the recognition and measurement of debt issuance costs. This accounting update is effective for annual and interim periods beginning on or after December 15, 2015. Early adoption is permitted, and the new standard must be adopted retrospectively. We are currently evaluating the impact that this pronouncement will have on our consolidated financial statements.

18. SUBSEQUENT EVENTS

Distribution to Partners

On April 29, 2015, 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 May 15, 2015. The distribution will be paid to unitholders of record as of May 8, 2015, of our available cash of $16.0 million at March 31, 2015, or $0.3475 per limited partner unit. We will pay $7.4 million to our public Class A common unitholders, while $8.6 million in the aggregate will be paid to EEP with respect to its Class A common units and subordinated units and Midcoast Holdings, L.L.C., with respect to its general partner interest.

Midcoast Operating Distribution

On April 29, 2015, the general partner of Midcoast Operating declared a cash distribution by Midcoast Operating payable to its partners of record as of May 8, 2015. Midcoast Operating will pay $27.8 million to us and $26.0 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 notes in our Annual Report on Form 10-K for the year ended December 31, 2014, as filed with the SEC on February 18, 2015.

RESULTS OF OPERATIONS—OVERVIEW

We are a growth-oriented Delaware limited partnership formed by EEP to serve as EEP's primary vehicle for owning and growing its natural gas and NGL midstream business in the United States. Midcoast Operating is a Texas limited partnership that owns a network of natural gas and NGL gathering and transportation systems, natural gas processing and treating facilities and NGL fractionation facilities primarily located in Texas and Oklahoma. Midcoast Operating also owns and operates natural gas, condensate and NGL logistics and marketing assets that primarily support its gathering, processing and transportation business. Through our ownership of Midcoast Operating's general partner, we control, manage and operate these systems.

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

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

- the volumes of natural gas, NGLs, condensate, and crude oil that we gather, process and transport on our systems;
- the price of natural gas, NGLs, condensate, and crude oil that we pay for and receive in connection with the services we provide;
- our ability to replace or renew existing contracts; and
- the supply and demand for natural gas, NGLs, condensate, and crude oil.

We conduct our business through two distinct reporting segments: Gathering, Processing and Transportation and Logistics and Marketing. We have established these reporting segments as strategic business units to facilitate the achievement of our long-term objectives, to aid in resource allocation decisions and to assess operational performance.

The following table reflects our operating income by business segment and corporate charges for each of the three-month periods ended March 31, 2015, and 2014.

	For the three-month period ended March 31,	
	2015	2014
	(in millions)	
Operating income (loss)		
Gathering, Processing and Transportation	$ (7.6)	$ (4.9)
Logistics and Marketing	(19.0)	17.2
Corporate	(1.7)	—
Total operating income (loss)	(28.3)	12.3
Interest expense, net	6.7	3.3
Other income (loss)	5.7	(1.3)
Income tax expense	0.8	1.0
Net income (loss)	$(30.1)	$ 6.7

Derivative Transactions and Hedging Activities

Contractual arrangements in our Gathering, Processing and Transportation segment and our Logistics and Marketing segment expose us to market risks associated with changes in commodity prices where we receive natural gas or NGLs in return for the services we provide or where we purchase natural gas or NGLs. Our unhedged commodity position is fully exposed to fluctuations in commodity prices, which can be significant during periods of price volatility. We use derivative financial instruments such as 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. 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.

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 March 31,	
	2015	2014
	(in millions)	
Gathering, Processing and Transportation segment:		
Hedge ineffectiveness	$ (4.0)	$ 1.7
Non-qualified hedges	(11.9)	(1.4)
Logistics and Marketing segment:		
Non-qualified hedges	(19.2)	4.3
Derivative fair value net gains (losses)	$(35.1)	$ 4.6

RESULTS OF OPERATIONS—BY SEGMENT

Gathering, Processing and Transportation

Our gathering, processing and transportation business includes natural gas and NGL gathering and transportation pipeline systems, natural gas processing and treating facilities and NGL fractionation facilities. Revenues for our gathering, processing and transportation business are determined primarily by the volumes of natural gas gathered, compressed, treated, processed, transported and sold through our systems; the volumes of NGLs sold; and the level of natural gas, NGL and condensate prices. The segment gross margin of our gathering, processing and transportation business, which we define as revenue generated from gathering, processing and transportation operations less the cost of natural gas and natural gas liquids purchased, is derived from the compensation we receive from customers in the form of fees or commodities we receive for providing our services, in addition to the proceeds we receive for the sales of natural gas, NGLs and condensate to affiliates and third parties.

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 March 31,	
	2015	2014
	(in millions)	
Operating revenues	$ 118.1	$ 203.3
Cost of natural gas and natural gas liquids	21.9	84.8
Segment gross margin	96.2	118.5
Operating and maintenance	50.8	64.4
General and administrative	16.3	24.0
Depreciation and amortization	36.7	35.0
Operating expenses	103.8	123.4
Operating loss	(7.6)	(4.9)
Other income (expense)	5.7	(1.2)
Net loss	$ (1.9)	$ (6.1)
Operating Statistics (MMBtu/d)		
East Texas	1,007,000	971,000
Anadarko	831,000	824,000
North Texas	287,000	272,000
Total	2,125,000	2,067,000
NGL Production (Bpd)	81,046	80,899

Three-month period ended March 31, 2015, compared with three-month period ended March 31, 2014

The operating loss of our Gathering, Processing and Transportation segment for the three-month period ended March 31, 2015, increased $2.7 million, as compared with the same period in 2014. The area most affected was segment gross margin, which decreased $22.3 million for the three-month period ended March 31, 2015, as compared with the same period in 2014.

Segment gross margin experienced a net decrease of $16.2 million due to non-cash, mark-to-market losses of $15.9 million and gains of $0.3 million for the three-month periods ended March 31, 2015, and March 31, 2014, respectively. These losses are primarily related to the reversal of previously recognized unrealized market-to-market gains as the underlying transactions were settled, partially offset by gains on non-qualifying hedges related to the decrease in commodity prices for the three-month period ended March 31, 2015, as compared with the same period in 2014.

Segment gross margin decreased $11.2 million for the three-month period ended March 31, 2015, as compared with the same period in 2014 due to decreased margins from lower commodity prices, net of hedges, related to contracts where we were paid in commodities for our services.

The decreases in segment gross margin were offset by approximately $4.4 million for the three-month period ended March 31, 2015, compared to the same period in 2014 of increased production volumes. The average daily volumes of our major systems for the three-month period ended March 31, 2015, increased by 58,000 MMBtu/d, or 3%, when compared to the same period in 2014. Volumes were lower during the same period in 2014 due to sustained freezing temperatures that resulted in shut-downs of production. These sustained freezing temperatures did not occur in 2015. The average NGL production for the three-month period ended March 31, 2015, was relatively flat, when compared to the same period in 2014.

Operating and maintenance costs decreased $13.6 million for the three-month period ended March 31, 2015, compared to the same period in 2014 primarily due to workforce reductions in December 2014 which resulted in a decrease in outside contract labor as well as other related benefit costs. In addition, other management cost reduction efforts in late 2014 and during the first quarter in 2015 were undertaken.

Depreciation and amortization expense increased $1.7 million for the three-month period ended March 31, 2015, compared with the same period of 2014 due to additional assets that were placed into service.

Other income was $5.7 million for the three-month period ended March 31, 2015, compared to a $1.2 million expense for the same period in 2014 as a result of increases in equity earnings on our investment in the Texas Express NGL system from higher volumes on the system and increases in demand payments from Texas Express shippers.

Future Prospects for Gathering, Processing and Transportation

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

Impact of Commodity Prices

Demand for our midstream services primarily depends upon the supply of natural gas and associated natural gas from crude oil development and the drilling rate for new wells. Demand for these services depends on overall economic conditions and commodity prices. Commodity prices for natural gas, NGLs, condensate and crude oil began declining during the fourth quarter of 2014 and into 2015. As a result, there have been reductions in drilling activity from producers in the areas we operate since the fourth quarter of 2014.

We have largely mitigated our direct commodity risk through our hedging program. We have hedged over approximately 90% and 70% of our direct commodity exposure for the remainder of 2015 and through 2016, respectively. Despite our hedging program, we still bear indirect commodity price exposure as lower drilling activity impacts the volumes on our systems. We expect this indirect impact on our volumes to improve as prices improve.

Expansion Projects

We are currently constructing two major expansion projects that are designed to increase natural gas processing, NGL production, residue gas and NGL transportation capacity. The paragraphs below summarize our commercially secured projects for the Natural Gas segment, which we expect to place into service in future periods.

Beckville Cryogenic Processing Plant

In April 2013, we announced plans to construct a cryogenic natural gas processing plant near Beckville in Panola County, Texas, which we refer to as the Beckville Processing Plant. This plant is expected to serve existing and prospective customers pursuing production in the Cotton Valley formation, which is comprised of approximately ten counties in East Texas and has been a steady producer of natural gas for decades, as well as the Eaglebine developments. Production from the Cotton Valley formation typically contains two to three gallons of NGLs per Mcf of natural gas. The region currently produces approximately 2.2 billion cubic feet per day, or Bcf/d, of natural gas with 73,000 Bpd of associated NGLs. Until recently, the primary exploitation method in the Cotton Valley formation has been vertical wells. Lower horizontal drilling costs, coupled with the latest fracturing technology, has brought significant interest back to this area. Economics associated with horizontal wells in the Cotton Valley formation compare favorably to other rich natural gas plays, which has encouraged producers to increase drilling activity in the region. 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. Related NGL takeaway infrastructure connecting the Beckville plant to third party NGL transportation systems was also constructed. We estimate the cost of constructing the plant to be approximately $155.0 million and expect it to be placed into commercial service in the second quarter of 2015.

The project is funded by us and EEP based on our proportionate ownership percentages in Midcoast Operating, which currently are 51.6% and 48.4%, respectively.

Eaglebine Developments

The Eaglebine is an emerging oil play in East Texas that spans over five counties and is comprised of multiple formations, including but not limited to, the Woodbine and Eagle Ford formations. We have a series of projects and an acquisition in this play. We have commenced construction of a lateral and associated facilities that will create gathering capacity of over 50 MMcf/d for rich natural gas to be delivered from Eaglebine production areas to our complex of cryogenic processing facilities in East Texas. The initial facilities are projected to be placed in service by late 2015, with the lateral expected to be in service in mid-2016. Given the proximity of our existing East Texas assets, this expansion into Eaglebine will allow us to offer gathering and processing services while leveraging assets on our existing footprint.

On February 27, 2015, we acquired from NGR its midstream operations in Leon, Madison and Grimes Counties, Texas. The acquisition consists of a natural gas gathering system that is currently in operation moving equity and third party production. For further details regarding the NGR acquisition, refer to Item 1. *Financial Statements* under Note 3. *Acquisitions*.

We estimate the aggregate cost of these projects and acquisitions described above to be approximately $160.0 million, of which $135.0 million is estimated to be spent in 2015. Funding is to be provided by us and EEP based on our proportionate ownership percentages in Midcoast Operating.

Logistics and Marketing

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

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

	For the three-month period ended March 31,	
	2015	2014
	(in millions)	
Operating revenues	$755.4	$1,443.6
Cost of natural gas and natural gas liquids	757.2	1,403.9
Segment gross margin	(1.8)	39.7
Operating and maintenance	12.6	17.3
General and administrative	3.0	3.2
Depreciation and amortization	1.6	2.0
Operating expenses	17.2	22.5
Operating income (loss)	$ (19.0)	$ 17.2

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 March 31, 2015, compared with three-month period ended March 31, 2014

The operating income of our Logistics and Marketing segment for the three-month period ended March 31, 2015, decreased $36.2 million, as compared with the same period in 2014. The area most affected was segment gross margin which decreased $41.5 million for the three-month period ended March 31, 2015, as compared with the same period in 2014.

Segment gross margin experienced a net decrease of $23.5 million due to non-cash, mark-to-market net losses of $19.2 million and gains of $4.3 million for the three-month periods ended March 31, 2015, and March 31, 2014, respectively. These losses are primarily related to the reversal of previously recognized unrealized market-to-market gains as the underlying transactions were settled, partially offset by gains on non-qualifying hedges related to the decrease in commodity prices for the three-month period ended March 31, 2015, as compared with the same period in 2014.

Our segment gross margin decreased $8.8 million for the three-month period ended March 31, 2015, compared with the same period in March 31, 2015 due to lower storage margins as a result of sale of liquids product inventory at prevailing market prices relative to the cost of product inventory. Our segment gross margin also decreased $2.9 million for the three-month period ended March 31, 2015, when compared to the same period of 2014, for non-cash charges to decrease the cost basis of our natural gas inventory to net realizable value. Since we hedge our storage positions financially, these charges are recovered when the physical natural gas inventory is sold or the financial hedges are realized.

Our segment gross margin was also impacted by decreased margins within our gas marketing function due to price differentials between market centers by approximately $6.2 million for the three-month period ended March 31, 2015, when compared to the same period of 2014. During the first quarter of 2014, we benefited from the difference between market centers in the Mid-Continent supply areas and market area in the Midwest which arose due to higher than usual demand from winter weather conditions in the Midwest.

Operating and administrative costs were $4.9 million lower for the three-month period ended March 31, 2015, compared with the three-month period ended March 31, 2014, due to workforce reductions in December 2014 which resulted in a decrease in outside contract labor as well as other related benefit costs. In addition, other management cost reduction efforts in late 2014 and during the first quarter in 2015 were undertaken which resulted in reduced maintenance costs, and reductions in rents and leases.

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 March 31,	
	2015	2014
	(in millions)	
General and administrative	1.7	—
Operating expenses	1.7	—
Operating loss	(1.7)	—
Interest expense, net	6.7	3.3
Other expense	—	(0.1)
Income tax expense	0.8	1.0
Net loss	$(9.2)	$(4.4)

Three-month period ended March 31, 2015, compared with three-month period ended March 31, 2014

General and administrative expenses increased $1.7 million for the three-month period ended March 31, 2015, as compared to the same period in 2014 due to increased professional fees and costs incurred since our initial public offering.

Interest expense increased $3.4 million for the three-month period ended March 31, 2015, as compared to the same period in 2014 primarily due to interest expense on our senior notes, which were issued in a private placement offering in September 2014.

LIQUIDITY AND CAPITAL RESOURCES

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

Capital projects at Midcoast Operating are currently funded by us and by EEP based on our proportionate ownership percentages in Midcoast Operating, which are 51.6% and 48.4%, respectively. Under Midcoast

Operating's partnership agreement, we and EEP each have the option to contribute our proportionate share of additional capital to Midcoast Operating if any additional capital contributions are necessary to fund expansion capital expenditures or other growth projects. To the extent that we or EEP elect not to make any such capital contributions, the contributing party will be permitted to make additional capital contributions to Midcoast Operating to the extent necessary to fully fund such expenditures in exchange for additional ownership interests in Midcoast Operating.

Under the Intercorporate Services Agreement, we reimburse EEP and its affiliates for the costs and expenses incurred in providing us with such services. 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.

Available Liquidity

Our primary source of liquidity is provided by the Credit Agreement. As set forth in the following table, at March 31, 2015, we had $540.3 million of liquidity available to us to meet our ongoing operational, investment and financing needs.

	(in millions)
Cash and cash equivalents	$ 5.3
Total credit available under Credit Agreement	850.0
Amounts outstanding under Credit Agreement	(315.0)
Total	$ 540.3

Equity and Debt Financing Activities

Credit Agreement

We, Midcoast Operating, and our material domestic subsidiaries are parties to the Credit Agreement, which permits aggregate borrowings of up to, at any one time outstanding, $850.0 million. The original term of the Credit Agreement was three years, with an initial maturity date of November 13, 2016, subject to four one-year requests for extensions. On September 30, 2014, we amended our Credit Agreement to extend the maturity date from November 13, 2016, to September 30, 2017; however, $140.0 million of commitments will expire on the original maturity date of November 13, 2016.

At March 31, 2015, we had $315.0 million in outstanding borrowings under the Credit Agreement at a weighted average interest rate of 2.7%. Under the Credit Agreement, we had net repayments of approximately $45.0 million during the three-month period ended March 31, 2015, which includes gross borrowings of $1,150.0 million and gross repayments of $1,195.0 million. At March 31, 2015, we were in compliance with the terms of our financial covenants in the Credit Agreement.

Senior Notes

Our senior notes in the aggregate amount of $400.0 million were issued in a private placement and consist of three tranches: $75.0 million of 3.56% Series A Senior Notes due in 2019; $175.0 million of 4.04% Series B Senior Notes due in 2021; and $150.0 million of 4.42% Series C Senior Notes due in 2024, collectively the Notes. All of the Notes pay interest semi-annually on March 31 and September 30, commencing on March 31, 2015. At March 31, 2015, we were in compliance with the terms of our financial covenants under the purchase agreement, pursuant to which we issued and sold the senior notes.

Financial Support Agreement

Midcoast Operating is party to a Financial Support Agreement with EEP, pursuant to which EEP provides 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.

Shelf-Registration Statement

From time to time, we may seek to satisfy liquidity needs through the issuance of registered debt or equity securities. To that end, in December 2014, we filed a shelf registration statement on Form S-3 with the SEC with a proposed aggregate offering price for all securities registered of $1.5 billion, which became effective on February 5, 2015.

Cash Requirements

Capital Spending

Acquisitions

We continue to assess ways to generate value for our unitholders, including reviewing opportunities that may lead to acquisitions or other strategic transactions, some of which may be material. We evaluate opportunities against operational, strategic and financial benchmarks before pursuing them. We expect to obtain the funds needed to make acquisitions through a combination of cash flows from operating activities, borrowings under the Credit Facility and the issuance of additional debt and equity securities. All acquisitions are considered in the context of the practical financing constraints presented by the capital markets.

In addition, EEP has indicated that it intends to offer us the opportunity to purchase additional interests in Midcoast Operating from time to time. These acquisitions sometimes referred to as "drop-down" transactions, will provide an alternative source of funding for EEP while at the same time providing an opportunity for meaningful growth in our cash flows. However, EEP is under no obligation to offer to sell us additional interests in Midcoast Operating, and we are under no obligation to buy any such additional interests. We believe that we will be well-positioned to acquire additional interests in Midcoast Operating if the opportunity arises.

Forecasted Expenditures

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

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

If EEP elects not to fund any capital expenditures at Midcoast Operating, we will have the option to fund all or a portion of EEP's proportionate share of such capital expenditures in exchange for additional interests in Midcoast Operating. As a result, if our interests in Midcoast Operating increase, our proportionate share of the capital expenditures incurred by Midcoast Operating will also increase proportionate to our interest in Midcoast

Operating. To the extent that EEP elects not to fund all or a portion of its proportionate share of Midcoast Operating's capital expenditures, and we elect not to fund any capital expenditures not funded by EEP, we expect that Midcoast Operating will not pursue the applicable capital projects associated with such unfunded capital expenditures.

At March 31, 2015, we had approximately $29.9 million in outstanding purchase commitments attributable to capital projects for the construction of assets that will be recorded as property, plant and equipment during 2015. The following table sets forth our estimated maintenance and expansion capital expenditures of $180.0 million, which includes $45.0 million of maintenance capital expenditures, for the year ending December 31, 2015. Although we anticipate making these expenditures in 2015, 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 March 31, 2015, we have incurred approximately $55.6 million in capital expenditures, including $6.0 million on maintenance capital activities. We also incurred $1.9 million in net contributions to fund our joint ventures. For the year ending December 31, 2015, we anticipate our capital expenditures to approximate the following:

	Total Forecasted Expenditures
	(in millions)
Capital Projects	
Beckville Cryogenic Processing Plant	$ 60
Eaglebine Developments	135
Compression Capital	20
Wellconnect Expansion Capital	40
Expansion Capital	45
Maintenance Capital Expenditure Activities	45
	345
Less: Joint Funding from:	
EEP [(1)]	165
	$180

(1) Joint funding is based upon EEP's current 48.4% ownership of Midcoast Operating.

Other Purchase Commitments

At March 31, 2015, we had approximately $5.9 million in outstanding purchase commitments attributable to commodity purchases.

Derivative Activities

We use derivative financial instruments (i.e., futures, forwards, swaps, options and other financial instruments with similar characteristics) to manage the risks associated with market fluctuations in commodity prices, as well as to reduce volatility to 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 financial instruments at fair market value in our Consolidated Statements of Financial Position. Price assumptions we use to value our non-qualifying derivative financial instruments can affect net income for each period. We use published market price information where available, or quotations from OTC market makers to find executable bids and offers. We may also use these inputs with internally developed methodologies that result in the best estimate of fair value. The valuations also reflect the potential impact of liquidating our position in an orderly manner over a reasonable period of time under present market conditions, including credit risk of our counterparties. The amounts reported in our consolidated financial statements change quarterly as these valuations are revised to reflect actual results, changes in market conditions or other factors, many of which are beyond our control.

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 March 31, 2015, for each of the indicated calendar years:

	Notional	2015	2016	2017	2018	2019 & Thereafter	Total (3)(4)
			(in millions)				
Swaps:							
Natural gas (1)	120,092,406	$ 0.9	$ 0.8	$ 0.2	$—	$—	$ 1.9
NGL (2)	3,973,250	19.8	9.8	(1.3)	—	—	28.3
Crude Oil (2)	3,581,650	12.1	1.0	—	—	—	13.1
Options:							
Natural gas—puts purchased (1)	4,672,000	3.5	1.3	—	—	—	4.8
Natural gas—puts written (1)	4,672,000	(3.5)	(1.3)	—	—	—	(4.8)
Natural gas—calls written (1)	2,609,500	—	(0.1)	—	—	—	(0.1)
Natural gas—calls purchased (1)	2,609,500	—	0.1	—	—	—	0.1
NGL—puts purchased (2)	5,116,500	29.3	39.9	1.0	—	—	70.2
NGL—calls written (2)	4,497,750	(0.2)	(2.4)	(1.2)	—	—	(3.8)
Crude Oil—puts purchased (2)	1,902,700	16.0	15.6	5.1	—	—	36.7
Crude Oil—calls written (2)	1,902,700	—	(0.5)	(2.5)	—	—	(3.0)
Forward contracts:							
Natural gas (1)	289,400,947	1.1	0.5	0.2	0.1	0.1	2.0
NGL (2)	20,288,854	4.9	0.9	—	—	—	5.8
Crude Oil (2)	774,682	(0.6)	—	—	—	—	(0.6)
Totals		$83.3	$65.6	$ 1.5	$ 0.1	$ 0.1	$150.6

(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 $0.7 million of losses at March 31, 2015.
(4) Excludes $22.6 million of cash collateral at March 31, 2015.

Cash Flow Analysis

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

	For the three-month period ended March 31, 2015	2014	Variance 2015 vs. 2014 Increase (Decrease)
		(in millions)	
Total cash provided by (used in):			
Operating activities	$ 168.2	$213.8	$ (45.6)
Investing activities	(103.0)	(15.3)	(87.7)
Financing activities	(59.9)	(90.4)	30.5
Net increase in cash and cash equivalents	5.3	108.1	(102.8)
Cash and cash equivalents at beginning of year	—	4.9	(4.9)
Cash and cash equivalents at end of period	$ 5.3	$113.0	$(107.7)

Operating Activities

Net cash provided by our operating activities decreased $45.6 million for the three-month period ended March 31, 2015, compared to the same period in 2014, primarily due to a $49.7 million decrease in our working capital accounts. This decrease is coupled with a $36.8 million decrease in net income and offset by increased derivative net losses of $39.7 million.

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

	For the three-month period ended March 31, 2015	2014	Variance 2015 vs. 2014
	(in millions)		
Changes in operating assets and liabilities, net of acquisitions:			
Receivables, trade and other	$ (11.6)	$ 3.5	$ (15.1)
Due from General Partner and affiliates	44.4	616.3	(571.9)
Accrued receivables	184.9	59.2	125.7
Inventory	48.2	26.2	22.0
Current and long-term other assets	(12.1)	(4.8)	(7.3)
Due to General Partner and affiliates	4.8	(478.3)	483.1
Accounts payable and other	(9.3)	(42.3)	33.0
Accrued purchases	(115.9)	(2.4)	(113.5)
Interest payable	(4.1)	0.5	(4.6)
Property and other taxes payable	(9.7)	(8.6)	(1.1)
Net change in working capital accounts	$ 119.6	$ 169.3	$ (49.7)

The changes in our operating assets and liabilities, as presented in our consolidated statements of cash flow for the three-month period ended March 31, 2015, compared to the same period in 2014, 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 three-month period ended March 31, 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 three-month period ended March 31, 2015;
- The change in working capital from accrued receivables of $125.7 million was a result of a decrease in accrued receivables for the three-month period ended March 31, 2015 due to collecting receivables at higher prices relative to current receivables recorded coupled with decreased sales of our receivables per our Receivables Agreement. For the three-month period ended March 31, 2014, our sales decreased due to a reduction in volumes offset by increased sales of receivables related to our Receivables Agreement; and
- The decline in accrued purchases for the three-month period ended March 31, 2015 was primarily the result of lower prices of natural gas and NGLs combined with lower volumes purchased. Due to seasonal inventory buildup by the end of 2014, we had enough inventory to sustain the demand for natural gas during the cold weather season, thus we did not need to purchase as much NGLs and natural gas to meet our commitments. For the three-month period ended March 31, 2014, payments and accruals were relatively flat.

Investing Activities

Net cash used in our investing activities during the three-month period ended March 31, 2015, increased by $87.7 million, compared to the same period in 2014, primarily due to:

- Increased acquisition of assets of $44.1 million when compared with the same period in 2014, primarily due to the purchase of NRG assets in February 2015. For further details regarding this acquisition, see Item 1. Financial Statements—*Note 3. "Acquisitions"*; and
- The change in the restricted cash balance of $50.2 million is primarily due to a decrease in restricted cash for the three-month period ended March 31, 2014 related to sales of our receivables in accordance with the Receivables Agreement and the cash collections we had yet to remit to the Enbridge subsidiary. Sales and collections were relatively flat for the three-month period ended March 31, 2015.

Financing Activities

Net cash used in our financing activities decreased $30.5 million for the three-month period ended March 31, 2015, compared to the same period in 2014, due to:

- Decreased net repayments on our credit facility of $40.0 million for the three-month period ended March 31, 2015;
- Increased contributions from noncontrolling interest of $19.0 million due to EEP's share of contributions for the acquisition of NGR's midstream business, offset by decreased contributions quarter-over-quarter, representing EEP's decreased ownership in Midcoast Operating, when compared to 2014;
- Decreased distributions to noncontrolling interest of $17.6 million primarily due to decreased ownership in Midcoast Operating coupled with decreased distributions quarter-over-quarter when compared to 2014; and
- Increased distributions to partners of $8.1 million for the three-month period ended March 31, 2015 compared to the same period in 2014.

SUBSEQUENT EVENTS

Distribution to Partners

On April 29, 2015, 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 May 15, 2015. The distribution will be paid to unitholders of record as of May 8, 2015, of our available cash of $16.0 million at March 31, 2015, or $0.3475 per limited partner unit. We will pay $7.4 million to our public Class A common unitholders, while $8.6 million in the aggregate will be paid to EEP with respect to its Class A common units and subordinated units and Midcoast Holdings, L.L.C., with respect to its general partner interest.

Midcoast Operating Distribution

On April 29, 2015, the general partner of Midcoast Operating declared a cash distribution by Midcoast Operating payable to its partners of record as of May 8, 2015. Midcoast Operating will pay $27.8 million to us and $26.0 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, 2014, filed on February 18, 2015, 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 March 31, 2015 and December 31, 2014.

	At March 31, 2015						At December 31, 2014	
			Wtd. Average Price (2)		Fair Value (3)		Fair Value (3)	
	Commodity	Notional (1)	Receive	Pay	Asset	Liability	Asset	Liability
						(in millions)		
Portion of contracts maturing in 2015								
Swaps								
Receive variable/pay fixed	Natural Gas	1,541,324	$ 2.61	$ 2.98	$ —	$ (0.6)	$ —	$ (0.7)
	NGL	504,250	$33.12	$40.52	$ 0.1	$ (3.8)	$ —	$ (6.8)
	Crude Oil	739,750	$52.35	$83.30	$ —	$(22.9)	$ —	$(27.4)
Receive fixed/pay variable	Natural Gas	1,728,938	$ 2.91	$ 2.71	$ 0.4	$ —	$ 3.7	$ —
	NGL	1,550,500	$46.19	$31.00	$24.0	$ (0.5)	$39.2	$ —
	Crude Oil	915,000	$90.93	$52.62	$35.0	$ —	$42.4	$ —
Receive variable/pay variable	Natural Gas	68,310,000	$ 2.56	$ 2.54	$ 2.6	$ (1.5)	$ 1.5	$ (1.7)
Physical Contracts								
Receive variable/pay fixed	Natural Gas	155,150	$ 2.39	$ 2.19	$ —	$ —	$ —	$ —
	NGL	80,000	$32.76	$41.89	$ —	$ (0.7)	$ —	$ (3.6)
	Crude Oil	11,000	$48.18	$51.64	$ —	$ —	$ —	$ —
Receive fixed/pay variable	Natural Gas	406,373	$ 2.46	$ 2.51	$ —	$ —	$ —	$ —
	NGL	398,525	$26.68	$21.93	$ 1.9	$ (0.1)	$19.8	$ —
	Crude Oil	109,000	$52.59	$50.02	$ 0.3	$ —	$ 0.5	$ —
Receive variable/pay variable	Natural Gas	192,448,455	$ 2.61	$ 2.61	$ 1.6	$ (0.5)	$ 2.2	$ (1.0)
	NGL	10,861,860	$18.50	$18.15	$ 3.9	$ (0.1)	$ 3.7	$ (1.0)
	Crude Oil	654,682	$46.53	$47.97	$ 1.0	$ (1.9)	$ 0.3	$ (1.7)
Portion of contracts maturing in 2016								
Swaps								
Receive variable/pay fixed	Natural Gas	363,514	$ 2.75	$ 3.41	$ —	$ (0.2)	$ —	$ (0.1)
	Crude Oil	415,950	$58.02	$82.69	$ —	$(10.2)	$ —	$ (8.1)
Receive fixed/pay variable	Natural Gas	465,600	$ 3.32	$ 3.16	$ 0.1	$ —	$ —	$ —
	NGL	823,500	$39.64	$27.63	$ 9.8	$ —	$ 9.3	$ —
	Crude Oil	415,950	$85.08	$58.02	$11.2	$ —	$ 9.1	$ —
Receive variable/pay variable	Natural Gas	44,959,000	$ 2.93	$ 2.91	$ 2.0	$ (1.1)	$ 0.5	$ (0.3)
Physical Contracts								
Receive fixed/pay variable	Natural Gas	63,591	$ 3.12	$ 2.98	$ —	$ —	$ —	$ —
	NGL	4,398	$29.86	$25.91	$ —	$ —	$ —	$ —
Receive variable/pay variable	Natural Gas	59,944,568	$ 3.05	$ 3.04	$ 0.9	$ (0.4)	$ 0.7	$ (0.4)
	NGL	8,944,071	$18.00	$17.89	$ 0.9	$ —	$ —	$ —
Portion of contracts maturing in 2017								
Swaps								
Receive variable/pay fixed	Natural Gas	24,030	$ 3.24	$ 3.48	$ —	$ —	$ —	$ —
	NGL	547,500	$23.81	$25.86	$ —	$ (1.1)	$ —	$ —
	Crude Oil	547,500	$61.30	$66.72	$ —	$ (2.9)	$ —	$ —
Receive fixed/pay variable	NGL	547,500	$23.59	$23.81	$ 0.3	$ (0.5)	$ 0.7	$ —
	Crude Oil	547,500	$66.78	$61.30	$ 2.9	$ —	$ 0.8	$ —
Receive variable/pay variable	Natural Gas	2,700,000	$ 3.44	$ 3.37	$ 0.2	$ —	$ —	$ —
Physical Contracts								
Receive variable/pay variable	Natural Gas	28,047,550	$ 3.36	$ 3.35	$ 0.3	$ (0.1)	$ 0.2	$ (0.1)
Portion of contracts maturing in 2018								
Physical Contracts								
Receive variable/pay variable	Natural Gas	5,787,810	$ 3.57	$ 3.56	$ 0.1	$ —	$ —	$ —
Portion of contracts maturing in 2019								
Physical Contracts								
Receive variable/pay variable	Natural Gas	2,187,810	$ 3.56	$ 3.53	$ 0.1	$ —	$ —	$ —
Portion of contracts maturing in 2020								
Physical Contracts								
Receive variable/pay variable	Natural Gas	359,640	$ 3.88	$ 3.85	$ —	$ —	$ —	$ —

(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 March 31, 2015, and December 31, 2014, respectively, discounted using the swap rate for the respective periods to consider the time value of money. Fair values are presented in millions of dollars and exclude credit valuation adjustments of approximately $0.1 million of losses at March 31, 2015 and $0.4 million of losses at December 31, 2014, as well as cash collateral received.

The following table provides summarized information about the fair value of expected cash flows of our outstanding commodity options at March 31, 2015 and December 31, 2014.

	At March 31, 2015						At December 31, 2014	
					Fair Value [3]		Fair Value [3]	
	Commodity	Notional [1]	Strike Price [2]	Market Price [2]	Asset	Liability	Asset	Liability
						(in millions)		
Portion of option contracts maturing in 2015								
Puts (purchased)	Natural Gas	3,025,000	$ 3.90	$ 2.78	$ 3.5	$—	$ 3.8	$—
	NGL	1,732,500	$43.32	$26.68	$29.3	$—	$40.2	$—
	Crude Oil	550,000	$81.56	$52.55	$16.0	$—	$18.8	$—
Calls (written)	Natural Gas	962,500	$ 5.05	$ 2.78	$ —	$—	$ —	$—
	NGL	1,113,750	$45.80	$26.06	$ —	$(0.2)	$ —	$(0.6)
	Crude Oil	550,000	$88.39	$52.55	$ —	$—	$ —	$(0.4)
Puts (written)	Natural Gas	3,025,000	$ 3.90	$ 2.79	$ —	$(3.5)	$ —	$(3.8)
Calls (purchased)	Natural Gas	962,500	$ 5.05	$ 2.78	$ —	$—	$ —	$—
Portion of option contracts maturing in 2016								
Puts (purchased)	Natural Gas	1,647,000	$ 3.75	$ 3.11	$ 1.3	$—	$ 1.0	$—
	NGL	2,836,500	$39.24	$26.46	$39.9	$—	$39.3	$—
	Crude Oil	805,200	$75.91	$58.23	$15.6	$—	$14.7	$—
Calls (written)	Natural Gas	1,647,000	$ 4.98	$ 3.11	$ —	$(0.1)	$ —	$(0.1)
	NGL	2,836,500	$45.14	$26.46	$ —	$(2.4)	$ —	$(3.2)
	Crude Oil	805,200	$86.68	$58.23	$ —	$(0.5)	$ —	$(2.7)
Puts (written)	Natural Gas	1,647,000	$ 3.75	$ 3.11	$ —	$(1.3)	$ —	$(1.0)
Calls (purchased)	Natural Gas	1,647,000	$ 4.98	$ 3.11	$ 0.1	$—	$ 0.1	$—
Portion of option contracts maturing in 2017								
Puts (purchased)	NGL	547,500	$21.70	$23.81	$ 1.0	$—	$ 1.2	$—
	Crude Oil	547,500	$63.00	$61.30	$ 5.1	$—	$ 4.1	$—
Calls (written)	NGL	547,500	$25.34	$23.81	$ —	$(1.2)	$ —	$(0.7)
	Crude Oil	547,500	$71.45	$61.30	$ —	$(2.5)	$ —	$(3.3)

(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 March 31, 2015, and December 31, 2014, respectively, discounted using the swap rate for the respective periods to consider the time value of money. Fair values are presented in millions of dollars and exclude any credit valuation adjustments of approximately $0.6 million and $0.7 million of losses at March 31, 2015 and December 31, 2014, respectively, as well as cash collateral received.

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

	March 31, 2015	December 31, 2014
	(in millions)	
Counterparty Credit Quality [1]		
AAA	$ 0.4	$ 0.1
AA [2]	69.5	74.4
A	47.4	67.1
Lower than A	10.0	18.0
	$127.3	$159.6

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

(2) Includes $22.6 million and $28.4 million of cash collateral at March 31, 2015 and December 31, 2014, respectively.

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 March 31, 2015. 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 March 31, 2015.

PART II—OTHER INFORMATION

Item 1. Legal Proceedings

Refer to Part I, Item 1. *Financial Statements*, "Note 12. *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, 2014, filed with the SEC on February 18, 2015.

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: May 1, 2015

By: /s/ C. Gregory Harper

C. Gregory Harper
President
(Principal Executive Officer)

Date: May 1, 2015

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*	Form of Performance Stock Unit Agreement of Midcoast Holdings, L.L.C.
31.1*	Certification of Principal Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2*	Certification of Principal Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1*	Certification of Principal Executive Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2*	Certification of Principal Financial Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
101.INS*	XBRL Instance Document.
101.SCH*	XBRL Taxonomy Extension Schema Document.
101.CAL*	XBRL Taxonomy Extension Calculation Linkbase Document.
101.DEF*	XBRL Taxonomy Extension Definition Linkbase Document.
101.LAB*	XBRL Taxonomy Extension Label Linkbase Document.
101.PRE*	XBRL Taxonomy Extension Presentation Linkbase Document.

Exhibit 31.1

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

I, C. Gregory Harper, certify that:

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

Date: May 1, 2015

By: /s/ C. Gregory Harper

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

Exhibit 31.2

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

I, Stephen J. Neyland, certify that:

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

Date: May 1, 2015

By: /s/ Stephen J. Neyland

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

Exhibit 32.1

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

The undersigned, being the Principal Executive Officer of Midcoast Energy Partners, L.P., hereby certifies that our Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2015 (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: May 1, 2015

By: /s/ C. Gregory Harper

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

Exhibit 32.2

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

The undersigned, being the Principal Financial Officer of Midcoast Energy Partners, L.P., hereby certifies that our Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2015 (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: May 1, 2015

By: /s/ Stephen J. Neyland

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