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, 2017

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 1-10934

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

Delaware	**39-1715850**
(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, smaller reporting company, or an emerging growth company. See the definitions of ''large accelerated filer,'' ''accelerated filer,'' ''smaller reporting company,'' and ''emerging growth company'' in Rule 12b-2 of the Exchange Act.

Large Accelerated Filer ☒		Accelerated Filer ☐
Non-Accelerated Filer ☐	(Do not check if a smaller reporting company)	Smaller reporting company ☐
Emerging growth company ☐		

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ☐

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 262,208,428 Class A common units outstanding as of May 8, 2017.

ENBRIDGE ENERGY PARTNERS, L.P.

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In this report, unless the context requires otherwise, references to "we," "us," "our," "EEP" or the "Partnership" are intended to mean Enbridge Energy Partners, L.P. and its consolidated subsidiaries. We refer to our general partner, Enbridge Energy Company, Inc., as our "General Partner." References to "Enbridge" refer collectively to Enbridge Inc., and its subsidiaries other than us. References to "Enbridge Management" refer to Enbridge Energy Management, L.L.C., the delegate of our General Partner that manages our business and affairs.

This Quarterly Report on Form 10-Q includes forward-looking statements, which are statements that frequently use words such as "anticipate," "believe," "consider," "continue," "could," "estimate," "evaluate," "expect," "explore," "forecast," "intend," "may," "opportunity," "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) our ability to complete the sale of our natural gas business pursuant to the agreement we have entered into with our General Partner in a timely manner or at all; (2) the effectiveness of the various other actions we have announced resulting from our strategic review process; (3) changes in the demand for the supply of, forecast data for, and price trends related to crude oil, liquid petroleum, natural gas and natural gas liquids, or NGLs, including the rate of development of the Alberta Oil Sands; (4) our ability to successfully complete and finance expansion projects; (5) the effects of competition, in particular, by other pipeline systems; (6) 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; (7) hazards and operating risks that may not be covered fully by insurance, including those related to Line 6B and any additional fines and penalties and injunctive relief assessed in connection with the crude oil release on that line; (8) costs in connection with complying with the settlement consent decree related to Line 6B and Line 6A, which is still subject to court approval, or the failure to receive court approval of, or material modifications to, such decree; (9) changes in or challenges to our tariff rates; (10) 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; and (11) permitting at federal, state and local level or renewals of rights of way. Any statements regarding sponsor expectations or intentions are based on information communicated to us by Enbridge, but there can be no assurance that these expectations or intentions will not change in the future.

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, 2016, which is available to the public over the Internet at the U.S. Securities and Exchange Commission's, or SEC's, website (www.sec.gov) and at our website (www.enbridgepartners.com).

PART I — FINANCIAL INFORMATION

Item 1. Financial Statements

ENBRIDGE ENERGY PARTNERS, L.P.

CONSOLIDATED STATEMENTS OF INCOME

	For the three months ended March 31,	
	2017	2016
	(unaudited; in millions, except per unit amounts)	
Operating revenues:		
Commodity sales (Note 14)	$ 525.7	$ 377.8
Commodity sales – affiliate (Notes 14 and 17)	6.1	5.2
Transportation and other services (Note 14)	622.2	656.0
Transportation and other services – affiliate (Note 17)	24.7	22.6
	1,178.7	1,061.6
Operating expenses:		
Commodity costs (Note 14)	471.4	335.4
Commodity costs – affiliate (Note 17)	16.4	12.6
Environmental costs, net of recoveries (Note 18)	10.3	16.9
Operating and administrative	103.2	96.5
Operating and administrative – affiliate (Note 17)	109.4	118.5
Power	74.5	72.8
Depreciation and amortization	146.2	140.9
	931.4	793.6
Operating income	247.3	268.0
Interest expense, net (Notes 11 and 14)	(106.8)	(112.9)
Allowance for equity used during construction (Note 5)	10.3	12.3
Other income (Note 10)	8.1	7.5
Income before income tax expense	158.9	174.9
Income tax expense (Note 15)	(1.5)	(2.5)
Net income	157.4	172.4
Less: Net income attributable to:		
Noncontrolling interest (Note 12)	68.3	68.8
Series 1 preferred unit distributions	22.5	22.5
Accretion of discount on Series 1 preferred units	1.2	1.1
Net income attributable to general and limited partner ownership interests in Enbridge Energy Partners, L.P.	$ 65.4	$ 80.0
Net income allocable to common units and i-units	$ 54.1	$ 24.1
Net income per common unit and i-unit (basic and diluted) (Note 3)	$ 0.15	$ 0.07
Weighted average common units and i-units outstanding (basic and diluted)	353.0	344.7

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

ENBRIDGE ENERGY PARTNERS, L.P.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	For the three months ended March 31,	
	2017	**2016**
	(unaudited; in millions)	
Net income	$157.4	$172.4
Other comprehensive income (loss), net of tax expense (Note 14)	9.4	(77.6)
Comprehensive income	166.8	94.8
Less:		
Net income attributable to noncontrolling interest (Note 12)	68.3	68.8
Net income attributable to Series 1 preferred unit distributions	22.5	22.5
Net income attributable to accretion of discount on Series 1 preferred units	1.2	1.1
Comprehensive income attributable to general and limited partner ownership interests in Enbridge Energy Partners, L.P.	$ 74.8	$ 2.4

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

ENBRIDGE ENERGY PARTNERS, L.P.

CONSOLIDATED STATEMENTS OF CASH FLOWS

	For the three months ended March 31,	
	2017	2016
	(unaudited; in millions)	
Cash provided by operating activities:		
Net income	$ 157.4	$ 172.4
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	146.2	140.9
Derivative fair value net (gains) losses (Note 14)	(7.3)	30.7
Environmental costs, net of recoveries	10.7	15.9
Distributions from investments in joint ventures	8.1	7.1
Equity earnings from investments in joint ventures	(8.1)	(7.1)
Gain on sales of assets	(10.6)	(0.5)
Allowance for equity used during construction	(10.3)	(12.3)
Amortization of debt issuance and hedging costs	9.6	10.6
Other	0.7	(1.4)
Changes in operating assets and liabilities (Note 16)	(62.7)	(90.0)
Net cash provided by operating activities	233.7	266.3
Cash used in investing activities:		
Additions to property, plant and equipment (Note 16)	(144.5)	(389.7)
Changes in restricted cash	9.6	11.6
Proceeds from the sale of net assets	216.4	—
Investments in joint ventures	(1,511.4)	—
Distributions from investments in joint ventures in excess of cumulative earnings	1.5	4.2
Other	(1.2)	(0.5)
Net cash used in investing activities	(1,429.6)	(374.4)
Cash provided by financing activities:		
Distributions to partners (Note 13)	(216.1)	(216.0)
Repayments to General Partner and affiliates (Note 17)	(750.0)	—
Borrowings from General Partner and affiliates (Note 17)	1,500.0	—
Net borrowings under credit facilities (Note 11)	280.0	405.0
Net commercial paper borrowings (repayments) (Note 11)	368.9	(136.4)
Acquisition of noncontrolling interest in subsidiary (Note 17)	(360.3)	—
Sale of noncontrolling interest in subsidiary (Note 17)	450.1	—
Contributions from noncontrolling interest (Note 17)	38.7	54.4
Distributions to noncontrolling interest (Note 17)	(119.1)	(7.6)
Other	(0.8)	(0.8)
Net cash provided by financing activities	1,191.4	98.6
Net decrease in cash and cash equivalents	(4.5)	(9.5)
Cash and cash equivalents at beginning of year	108.8	148.1
Cash and cash equivalents at end of period	$ 104.3	$ 138.6

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

ENBRIDGE ENERGY PARTNERS, L.P.

CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

	March 31, 2017	December 31, 2016
	(unaudited; in millions)	
ASSETS		
Current assets:		
Cash and cash equivalents (Note 7)	$ 104.3	$ 108.8
Restricted cash (Notes 7 and 17)	14.9	24.5
Receivables, trade and other, net of allowance for doubtful accounts of $2.3 million and $2.4 million at March 31, 2017 and December 31, 2016, respectively	22.4	14.5
Due from General Partner and affiliates (Note 17)	102.5	90.6
Accrued receivables	60.5	39.7
Inventory (Note 8)	39.4	30.9
Other current assets (Notes 5 and 14)	84.6	92.2
	428.6	401.2
Property, plant and equipment, net (Notes 5 and 9)	16,696.4	16,722.6
Equity investments in joint ventures (Notes 6 and 10)	1,870.6	360.7
Intangible assets, net	253.5	258.5
Other assets, net (Note 14)	130.0	160.3
Assets held for sale (Note 6)	—	206.8
	$19,379.1	$18,110.1
LIABILITIES AND PARTNERS' CAPITAL		
Current liabilities:		
Accounts payable and other (Notes 5, 7 and 14)	$ 371.5	$ 409.6
Due to General Partner and affiliates (Note 17)	488.9	213.9
Accrued purchases	179.6	176.8
Interest payable	113.1	95.1
Environmental liabilities (Note 18)	97.5	99.9
Property and other taxes payable (Note 15)	104.9	106.9
Note payable to General Partner (Note 17)	1,500.0	—
	2,855.5	1,102.2
Long-term debt (Note 11)	8,534.8	7,884.4
Loans from General Partner and affiliates (Note 17)	—	750.0
Due to General Partner and affiliates (Note 17)	—	328.3
Other long-term liabilities (Notes 14, 15 and 18)	228.7	222.7
	11,619.0	10,287.6
Commitments and contingencies (Note 18)		
Partners' capital: (Note 13)		
Series 1 preferred units (48,000,000 authorized and issued at March 31, 2017 and December 31, 2016)	1,192.7	1,191.5
Class D units (66,100,000 authorized and issued at March 31, 2017 and December 31, 2016)	2,479.2	2,517.6
Class E units (18,114,975 authorized and issued at March 31, 2017 and December 31, 2016)	773.9	778.2
Class A common units (262,208,428 outstanding at March 31, 2017 and December 31, 2016)	—	—
Class B common units (7,825,500 authorized and issued at March 31, 2017 and December 31, 2016)	—	—
i-units (83,983,816 and 81,857,168 authorized and issued at March 31, 2017 and December 31, 2016, respectively)	—	—
Incentive distribution units (1,000 authorized and issued at March 31, 2017 and December 31, 2016)	489.9	495.2
General Partner	(730.4)	(666.8)
Accumulated other comprehensive loss (Notes 13 and 14)	(329.9)	(339.3)
Total Enbridge Energy Partners, L.P. partners' capital	3,875.4	3,976.4
Noncontrolling interest (Note 12)	3,884.7	3,846.1
Total partners' capital	7,760.1	7,822.5
	$19,379.1	$18,110.1

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

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (unaudited)

1. ORGANIZATION AND NATURE OF OPERATIONS

We have prepared the accompanying unaudited interim consolidated financial statements in accordance with generally accepted accounting principles in the United States of America, or GAAP, for 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 footnotes required by GAAP for complete consolidated financial statements. In the opinion of management, they contain all adjustments, consisting only of normal recurring adjustments, which management considers necessary to present fairly our financial position as of March 31, 2017, our results of operations for the three months ended March 31, 2017 and 2016, and our cash flows for the three months ended March 31, 2017 and 2016. We derived our consolidated statement of financial position as of December 31, 2016 from the audited financial statements included in our Annual Report on Form 10-K for the fiscal year ended December 31, 2016. Our results of operations for the three months ended March 31, 2017 and 2016, 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 crude oil, seasonality of portions of our natural gas business, 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 and the effect of environmental costs and related insurance recoveries on our Lakehead system. Our unaudited interim consolidated financial statements should be read in conjunction with our audited consolidated financial statements and notes thereto presented in our Annual Report on Form 10-K for the fiscal year ended December 31, 2016.

2. CHANGES IN ACCOUNTING POLICY

Future Accounting Policy Changes

Restricted Cash Presentation on Statement of Cash Flows

ASU No. 2016-18, was issued in November 2016 with the intent to add or clarify guidance on the classification and presentation of changes in restricted cash and restricted cash equivalents within the cash flow statement. The amendments require that changes in restricted cash and restricted cash equivalents should be included within cash and cash equivalents when reconciling the opening and closing period amounts shown on the statement of cash flows. We are currently assessing the impact of the new standard on our consolidated financial statements. The accounting update is effective for fiscal years beginning after December 15, 2017 and is to be applied on a retrospective basis.

Recognition of Leases

ASU No. 2016-02 was issued in February 2016 with the intent to increase transparency and comparability among organizations by recognizing lease assets and lease liabilities on the consolidated statements of financial position and disclosing additional key information about leasing arrangements. We are currently assessing the impact of the new standard on our consolidated financial statements. The accounting update is effective for fiscal years beginning after December 15, 2018 and is to be applied using a modified retrospective approach.

Recognition and Measurement of Financial Assets and Liabilities

ASU No. 2016-01 was issued in January 2016 with the intent to address certain aspects of recognition, measurement, presentation, and disclosure of financial assets and liabilities. The amendments revise accounting related to the classification and measurement of investments in equity securities, the presentation of certain fair value changes for financial liabilities measured at fair value, and the disclosure requirements associated with the fair value of financial instruments. We are currently assessing the impact of the new standard on our consolidated financial statements. The accounting update is effective for fiscal years beginning after December 15, 2017 and is to be applied by means of a cumulative-effect adjustment to the statements of financial position as of the beginning of the fiscal year of adoption.

Revenues from Contracts with Customers

Since May 2014, ASU Nos. 2014-09, 2015-14, 2016-08, 2016-10 and 2016-12 were issued with the intent of significantly enhancing consistency and comparability of revenue recognition practices across entities and industries. The new standard establishes a single, principles-based five-step model to be applied to all contracts with customers

2. CHANGES IN ACCOUNTING POLICY – (continued)

and introduces new and enhanced disclosure requirements. The standard is effective January 1, 2018. The new revenue standard permits either a full retrospective method of adoption with restatement of all prior periods presented, or a modified retrospective method with the cumulative effect of applying the new standard recognized as an adjustment to opening retained earnings in the period of adoption. We are currently assessing which transition method to use.

We reviewed a sample of our revenue contracts in order to evaluate the effect of the new standard on our revenue recognition practices. Based on our initial assessment, estimates of variable consideration which will be required under the new standard for certain contracts may result in changes to the pattern or timing of revenue recognition for those contracts. While we have not yet completed our assessment, we tentatively do not expect these changes to have a material impact on our consolidated net income (loss). We are also developing processes to generate the disclosures required under the new standard.

3. NET INCOME PER LIMITED PARTNER UNIT

We allocate our net income among our Series 1 Preferred Units, or Preferred Units, our General Partner interest and our limited partner units using the two-class method in accordance with applicable authoritative accounting guidance. Under the two-class method, we allocate our net income attributable to our General Partner and our limited partners according to the distribution formula for available cash as set forth in our partnership agreement. We allocate our net income to our limited partners owning Class D units and Class E units equal to the distributions that they receive. We also allocate any earnings in excess of distributions to our General Partner and limited partners owning Class A and Class B common units and i-units utilizing the distribution formula for available cash specified in our partnership agreement. We allocate any distributions in excess of earnings for the period to our General Partner and limited partners owning Class A and B common units and i-units based on their sharing of losses of 2% and 98%, respectively, as set forth in our partnership agreement. We allocate distributions to the General Partner and limited partners based upon the distribution rates and percentages set forth in the following table:

Distribution Targets	Portion of Quarterly Distribution Per Unit	Percentage Distributed to General Partner and IDUs[(1)]	Percentage Distributed to Limited partners
Minimum Quarterly Distribution	Up to $0.5435	2%	98%
First Target Distribution	>$0.5435	25%	75%

(1) For distributions in excess of the Minimum Quarterly Distribution, this percentage includes both the General Partner's distributions of 2% and the distribution to the Incentive Distribution Unit holder, a wholly-owned subsidiary of our General Partner.

Simplification of Incentive Distributions

On April 27, 2017, a wholly-owned subsidiary of our General Partner irrevocably waived all of its rights associated with its 66.1 million Class D units and its 1,000 incentive distribution units, or IDUs, in exchange for the issuance of 1,000 Class F units. The irrevocable waiver, or the Waiver, is effective with respect to distributions declared with a record date after April 27, 2017.

The Class F units are entitled to receive an incentive distribution for amounts distributed in excess of the Minimum Quarterly Distribution as described in the following table:

Distribution Targets	Portion of Quarterly Distribution Per Unit	Percentage Distributed to General Partner and Class F Units[(1)]	Percentage Distributed to Limited partners
Minimum Quarterly Distribution	Up to $0.295	2%	98%
First Target Distribution	>$0.295 to $0.35	15%	85%
Over First Target Distribution	>$0.35	25%	75%

(1) For distributions in excess of the Minimum Quarterly Distribution, this percentage includes both the General Partner's distributions of 2% and the distribution to the Class F Units.

3. NET INCOME PER LIMITED PARTNER UNIT – (continued)

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

	For the three months ended March 31,	
	2017	2016
	(in millions, except per unit amounts)	
Net income	$ 157.4	$ 172.4
Less: Net income attributable to:		
Noncontrolling interest	68.3	68.8
Series 1 preferred unit distributions	22.5	22.5
Accretion of discount on Series 1 preferred units	1.2	1.1
Net income attributable to general and limited partner interests in Enbridge Energy Partners, L.P.	65.4	80.0
Distributions:		
Incentive distributions[(1)]	(3.7)	(5.2)
Distributed earnings attributed to our General Partner	(3.2)	(5.2)
Distributed earnings attributed to Class D and Class E units	(6.3)	(49.1)
Total distributed earnings to our General Partner, Class D and Class E units and IDUs	(13.2)	(59.5)
Total distributed earnings attributed to our common units and i-units	(146.4)	(201.7)
Total distributed earnings	(159.6)	(261.2)
Overdistributed earnings	$ (94.2)	$(181.2)
Weighted average common units and i-units outstanding	353.0	344.7
Basic and diluted earnings per unit:		
Distributed earnings per common unit and i-unit[(2)]	$ 0.41	$ 0.59
Overdistributed earnings per common unit and i-unit[(3)]	(0.26)	(0.52)
Net income per common unit and i-unit (basic and diluted)[(4)]	$ 0.15	$ 0.07

(1) For the three months ended March 31, 2017, Class D units and IDUs were not entitled to distributions; incentive distributions were made to Class F units. For the three months ended March 31, 2016, incentive distributions were made to IDUs.

(2) Represents the total distributed earnings to common units and i-units divided by the weighted average number of common units and i-units outstanding for the period.

(3) Represents the common units' and i-units' share (98%) of distributions in excess of earnings divided by the weighted average number of common units and i-units outstanding for the period and overdistributed earnings allocated to the common units and i-units based on the distribution waterfall that is outlined in our partnership agreement.

(4) For the three months ended March 31, 2017 and 2016, 43,201,310 anti-dilutive Preferred units, and 18,114,975 anti-dilutive Class E units were excluded from the if-converted method of calculating diluted earnings per unit. For the three months ended March 31, 2017, 66,100,000 of Class D units were excluded from the if-converted method of calculating diluted earnings per unit as the General Partner irrevocably waived all of its rights associated with the Class D units effective April 27, 2017. For the three months ended March 31, 2016, 66,100,000 anti-dilutive Class D Units were excluded from the if-converted method of calculating diluted earnings per unit.

4. 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, because each business segment requires different operating strategies. We have segregated our business activities into two distinct operating segments:

- Liquids; and
- Natural Gas.

4. SEGMENT INFORMATION – (continued)

The following tables present certain financial information relating to our business segments and other activities. Interest expense, allowance for equity used during construction, income tax expense, noncontrolling interest, and certain other costs are not allocated to the business segments. These items are presented in "Other" in the tables below:

	As of and for the three months ended March 31, 2017			
	Liquids	Natural Gas	Other	Total
	(in millions)			
Operating revenues:[1]				
Commodity sales	$ —	$ 531.8	$ —	$ 531.8
Transportation and other services	604.7	42.2	—	646.9
	604.7	574.0	—	1,178.7
Operating expenses:				
Commodity costs	—	487.8	—	487.8
Environmental costs, net of recoveries	10.3	—	—	10.3
Operating and administrative	140.0	66.6	6.0	212.6
Power	74.5	—	—	74.5
Depreciation and amortization	108.7	37.5	—	146.2
	333.5	591.9	6.0	931.4
Operating income (loss)	271.2	(17.9)	(6.0)	247.3
Interest expense, net	—	—	(106.8)	(106.8)
Allowance for equity used during construction	—	—	10.3	10.3
Other income	—	8.1[2]	—	8.1
Income (loss) before income tax expense	271.2	(9.8)	(102.5)	158.9
Income tax expense	—	—	(1.5)	(1.5)
Net income (loss)	271.2	(9.8)	(104.0)	157.4
Less: Net income attributable to:				
Noncontrolling interest	—	—	68.3	68.3
Series 1 preferred unit distributions	—	—	22.5	22.5
Accretion of discount on Series 1 preferred units	—	—	1.2	1.2
Net income (loss) attributable to general and limited partner ownership interests in Enbridge Energy Partners, L.P.	$ 271.2	$ (9.8)	$(196.0)	$ 65.4
Total assets	$14,419.3[4]	$4,845.6[3]	$ 114.2	$19,379.1
Capital expenditures (excluding acquisitions)	$ 88.0	$ 9.4	$ 0.2	$ 97.6

(1) There were no intersegment revenues for the three months ended March 31, 2017.

(2) Other income for our Natural Gas segment includes our equity investment in the Texas Express NGL system.

(3) Total assets for our Natural Gas segment includes $359.2 million for our equity investment in the Texas Express NGL system.

(4) Total assets for our Liquids segment includes $1,511.4 million for our equity investment in the Bakken Pipeline System.

4. SEGMENT INFORMATION – (continued)

	As of and for the three months ended March 31, 2016			
	Liquids	Natural Gas	Other	Total
	(in millions)			
Operating revenues:[1]				
Commodity sales	$ —	$ 383.0	$ —	$ 383.0
Transportation and other services	629.7	48.9	—	678.6
	629.7	431.9	—	1,061.6
Operating expenses:				
Commodity costs	—	348.0	—	348.0
Environmental costs, net of recoveries	16.9	—	—	16.9
Operating and administrative	137.2	74.3	3.5	215.0
Power	72.8	—	—	72.8
Depreciation and amortization	101.4	39.5	—	140.9
	328.3	461.8	3.5	793.6
Operating income (loss)	301.4	(29.9)	(3.5)	268.0
Interest expense, net	—	—	(112.9)	(112.9)
Allowance for equity used during construction	—	—	12.3	12.3
Other income	—	7.1[2]	0.4	7.5
Income (loss) before income tax expense	301.4	(22.8)	(103.7)	174.9
Income tax expense	—	—	(2.5)	(2.5)
Net income (loss)	301.4	(22.8)	(106.2)	172.4
Less: Net income attributable to:				
Noncontrolling interest	—	—	68.8	68.8
Series 1 preferred unit distributions	—	—	22.5	22.5
Accretion of discount on Series 1 preferred units	—	—	1.1	1.1
Net income (loss) attributable to general and limited partner ownership interests in Enbridge Energy Partners, L.P.	$ 301.4	$ (22.8)	$(198.6)	$ 80.0
Total assets	$13,650.3	$5,026.4[3]	$ 150.5	$18,827.2
Capital expenditures (excluding acquisitions)	$ 264.3	$ 18.6	$ (0.9)	$ 282.0

(1) There were no intersegment revenues for the three months ended March 31, 2016.

(2) Other income for our Natural Gas segment includes our equity investment in the Texas Express NGL system.

(3) Total assets for our Natural Gas segment includes $368.0 million for our equity investment in the Texas Express NGL system.

5. REGULATORY MATTERS

Regulatory Accounting

Due to over or under recovery adjustments made in accordance with the Federal Energy Regulatory Commission, or FERC, authoritative guidance and our cost-of-service recovery model, we recognize assets and liabilities for regulatory purposes. The assets and liabilities that we recognize for regulatory purposes are recorded on a net basis in ''Other current assets'' or ''Accounts payable and other,'' respectively, on our consolidated statements of financial position. These regulatory assets and liabilities are amortized on a straight-line basis over a one-year recovery period. Our over and under recovery revenue adjustments and net regulatory asset amortization for the three months ended March 31, 2017 and 2016 are as follows:

	For the three months ended March 31,	
	2017	2016
	(in millions)	
Net regulatory asset balance at beginning of period	$ 11.9	$29.9
Current period (over) under recovery revenue adjustments	(39.0)	7.7
Amortization of prior year regulatory asset	(7.0)	(6.4)
Net regulatory asset (liability) balance at end of period	$(34.1)	$31.2

Allowance for Equity Used During Construction

We are permitted to capitalize and recover costs for rate-making purposes that include an allowance for equity costs during construction, referred to as AEDC. In connection with construction of the Eastern Access Projects, Line 3 Replacement and Mainline Expansion Projects, we recorded $10.3 million and $12.3 million of ''Allowance for equity used during construction'' on our consolidated statements of income for the three months ended March 31, 2017 and 2016, respectively, and a corresponding amount in ''Property, plant and equipment, net'' on our consolidated statements of financial position at March 31, 2017 and 2016, respectively.

6. ACQUISTIONS AND DISPOSITIONS

On February 15, 2017, through our joint venture with Marathon Petroleum Corporation, or MPC, we acquired a minority stake in the Bakken Pipeline System. We funded the $1.5 billion acquisition through a bridge loan provided by Enbridge (U.S.) Inc., or EUS, an affiliate of our General Partner. For further details regarding our acquisition, refer to Note 10. *Equity Investments in Joint Ventures*. For further details regarding our funding arrangement, refer to Note 17. *Related Party Transactions.*

On March 1, 2017, we sold the Ozark Pipeline System to a subsidiary of MPLX LP for cash proceeds of approximately $219.6 million, including reimbursement costs. These assets were part of our Liquids segment. The gain on disposal of $10.6 million for the three months ended March 31, 2017, is included in ''Operating and administrative'' expense on our consolidated statements of income.

7. CASH AND CASH EQUIVALENTS

We extinguish liabilities when a creditor has relieved us of our obligation, which occurs when our financial institution honors a check that the creditor has presented for payment. Accordingly, obligations for which we have made payments that have not yet been presented to the financial institution totaling approximately $7.5 million and $9.8 million at March 31, 2017, and December 31, 2016, respectively, are included in ''Accounts payable and other'' on our consolidated statements of financial position.

Restricted Cash

Restricted cash is comprised entirely of cash collected on behalf of an Enbridge subsidiary for sales of certain accounts receivables that have not yet been remitted to the Enbridge subsidiary. For further information refer to Note 17. *Related Party Transactions*.

8. INVENTORY

Our inventory is comprised of the following:

	March 31, 2017	December 31, 2016
	(in millions)	
Materials and supplies	$ 1.9	$ 1.8
Crude oil inventory	0.3	1.3
Natural gas and NGL inventory	37.2	27.8
Total inventory	$39.4	$30.9

9. PROPERTY, PLANT AND EQUIPMENT

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

	March 31, 2017	December 31, 2016
	(in millions)	
Land	$ 101.8	$ 103.2
Rights-of-way	935.8	932.2
Pipelines	10,640.7	10,448.6
Pumping equipment, buildings and tanks	4,888.9	4,953.8
Compressors, meters and other operating equipment	2,184.2	2,182.6
Vehicles, office furniture and equipment	238.0	233.8
Processing and treating plants	630.9	630.0
Construction in progress	871.0	896.8
Total property, plant and equipment	20,491.3	20,381.0
Accumulated depreciation	(3,794.9)	(3,658.4)
Property, plant and equipment, net	$16,696.4	$16,722.6

10. EQUITY INVESTMENTS IN JOINT VENTURES

The following table presents our investments in unconsolidated affiliates by business segment at the dates indicated. We account for these investments using the equity method.

	Ownership Interest	March 31, 2017	December 31, 2016
		(in millions)	
Liquids:			
MarEn Bakken Company LLC	75.0%	$1,511.4	$ —
Natural Gas:			
Texas Express Pipeline LLC	35.0%	331.0	332.8
Texas Express Gathering LLC	35.0%	28.2	27.9
Total equity investments in joint ventures		$1,870.6	$360.7

10. EQUITY INVESTMENTS IN JOINT VENTURES – (continued)

Liquids Segment Investment

On February 15, 2017, our joint venture with MPC, MarEn Bakken Company LLC, or MarEn, closed its acquisition, or the Bakken Transaction, with Bakken Holdings Company LLC, or Bakken Holdings, an affiliate of Energy Transfer Partners, L.P. and Sunoco Logistics Partners L.P., to acquire a 49% equity interest in Bakken Pipeline Investments LLC, or BPI. BPI owns 75% of the Bakken Pipeline System. Under this arrangement, we and MPC indirectly hold 75% and 25%, respectively, of MarEn's 49% interest in BPI. The purchase price of our effective 27.6% interest in the Bakken Pipeline System was $1.5 billion.

	February 15, 2017
	(in millions)
Fair value of assets acquired:	
Current assets	$ 56.9
Property, plant and equipment	1,610.4
Intangible assets	547.3
Goodwill	14.4
Current liabilities	(88.3)
Other long-term liabilities	(640.7)
	$1,500.0
Purchase Price:	
Cash	$1,500.0

We account for our investment in MarEn under the equity method of accounting. For the three months ended March 31, 2017, we did not recognize equity earnings for this investment as the Bakken Pipeline System has not yet been placed into service. For the three months ended March 31, 2017, we recognized $11.4 million of interest costs, which were capitalized and recorded as part of our equity method investment in MarEn.

Our equity investment includes the unamortized excess of the purchase price over the underlying net book value, or basis difference, of the investees' assets at the purchase date. The basis difference is comprised of $14.4 million in goodwill and $931.4 million in amortizable assets.

Natural Gas Segment Investments

We have a 35% aggregate indirect interest in the Texas Express NGL system, which is comprised of two joint ventures with third parties that together include a 593-mile NGL intrastate transportation pipeline and a related NGL gathering system. We recognized equity income of $8.1 million and $7.1 million for the three months ended March 31, 2017 and 2016, respectively, in ''Other income'' on our consolidated statements of income related to our investment in the system.

11. DEBT

The following table presents the primary components of our outstanding indebtedness with third parties and the weighted average interest rates associated with each component as of March 31, 2017, before the effect of our interest rate hedging activities. Our indebtedness with related parties is discussed in Note 17. *Related Party Transactions.*

	Interest Rate	March 31, 2017	December 31, 2016
		(in millions)	
EEP debt obligations:			
Commercial Paper[1]	1.810%	$ 762.4	$ 392.5
Credit Facilities due 2018-2020	2.067%	1,525.0	1,265.1
Senior Notes due April 2018	6.500%	400.0	400.0
Senior Notes due March 2019	9.875%	500.0	500.0
Senior Notes due March 2020	5.200%	500.0	500.0
Senior Notes due October 2020	4.375%	500.0	500.0
Senior Notes due September 2021	4.200%	600.0	600.0
Senior Notes due October 2025	5.875%	500.0	500.0
Senior Notes due June 2033	5.950%	200.0	200.0
Senior Notes due December 2034	6.300%	100.0	100.0
Senior Notes due April 2038	7.500%	400.0	400.0
Senior Notes due September 2040	5.500%	550.0	550.0
Senior Notes due October 2045	7.375%	600.0	600.0
Junior subordinated notes due 2067	8.050%	400.0	400.0
OLP debt obligations:			
Senior Notes due October 2018	7.000%	100.0	100.0
Senior Notes due October 2028	7.125%	100.0	100.0
MEP debt obligations:			
MEP Credit Agreement	3.533%	440.0	420.0
MEP Series A Senior Notes due September 2019	3.560%	75.0	75.0
MEP Series B Senior Notes due September 2021	4.040%	175.0	175.0
MEP Series C Senior Notes due September 2024	4.420%	150.0	150.0
Total principal amount of debt obligations		8,577.4	7,927.6
Other:			
Unamortized discount		(6.9)	(6.2)
Unamortized debt issuance costs		(35.7)	(37.0)
Total long-term debt		$8,534.8	$7,884.4

(1) Individual issuances of commercial paper generally mature in 90 days or less, but are supported by our Credit Facilities and are therefore considered long-term debt.

Interest Cost

Our interest cost for the three months ended March 31, 2017, and 2016, is comprised of the following:

	For the three months ended March 31, 2017	2016
	(in millions)	
Interest cost incurred	$124.1	$122.0
Less: Interest capitalized	17.3	9.1
Interest expense	$106.8	$112.9

11. DEBT – (continued)

Credit Facilities and Commercial Paper

Under our multi-year senior unsecured revolving credit facility and our 364-day revolving credit agreement, together referred to as the Credit Facilities, we had net borrowings of approximately $260.0 million during the period ended March 31, 2017, which includes gross borrowings of $3.6 billion and gross repayments of $3.4 billion.

Under our commercial paper program, we had net borrowings of approximately $368.9 million during the period ended March 31, 2017, which includes gross borrowings of $2.0 billion and gross repayments of $1.6 billion.

Under our credit agreement with EUS, an affiliate of Enbridge and the owner of our General Partner, or the EUS 364-day Credit Facility, we made gross repayments of approximately $750 million during the period ended March 31, 2017. Under our EUS Credit Agreement we had gross borrowings of approximately $1.5 billion during the period ended March 31, 2017. For further information, refer to Note 17. *Related party Transactions*.

We have the ability and intent to refinance all of our commercial paper obligations on a long-term basis through borrowings under our Credit Facilities. Accordingly, such amounts have been classified as ‘‘Long-term debt’’ in our accompanying consolidated statements of financial position.

At March 31, 2017, we had approximately $960.8 million of unutilized commitments under the terms of our Credit Facilities and the EUS 364-day Credit Facility, determined as follows:

	(in millions)
Total commitments under our Credit Facilities	$2,625.0
Total commitments under the EUS 364-day Credit Facility	750.0
Total commitments under the EUS Credit Agreement	1,500.0
Less: Amounts outstanding under our Credit Facilities	1,525.0
Amounts outstanding under the EUS Credit Agreement	1,500.0
Principal amount of commercial paper outstanding	762.4
Letters of credit outstanding	126.8
Total unutilized commitments at March 31, 2017	$ 960.8

MEP Credit Agreement

Midcoast Energy Partners, L.P. or MEP, Midcoast Operating, and their material subsidiaries are party to a senior revolving credit facility, which we refer to as the MEP Credit Agreement, which permits aggregate borrowings of up to $670.0 million, at any one time outstanding. The original term of the MEP Credit Agreement was three years with an initial maturity date of November 13, 2016, subject to four one-year requests for extensions at the lenders' discretion, two of which we have utilized. The MEP Credit Agreement's current maturity date is September 30, 2018; however, $25.0 million of commitments expire on September 30, 2017. During the three months ended March 31, 2017, MEP had net borrowings of approximately $20.0 million, which includes gross borrowings of $1,600.0 million and gross repayments of $1,580.0 million.

On April 27, 2017, we entered into a definitive agreement with our General Partner to sell all of our ownership interests in our natural gas business. MEP's outstanding debt will not be repaid at the closing of the transaction; rather it will remain outstanding and continue as an ongoing obligation of MEP. For further information, refer to Note 19. *Subsequent Events*.

Debt Covenants

As of March 31, 2017, we and our consolidated subsidiaries were in compliance or deemed in compliance with the terms of our financial covenants under our consolidated debt agreements.

Fair Value of Debt Obligations

The carrying amounts of our outstanding commercial paper, borrowings under our Credit Facilities, the EUS 364-day Credit Facility, the EUS Credit Agreement and the MEP Credit Agreement approximate their fair values at March 31, 2017 and December 31, 2016, respectively, due to the short-term nature and frequent repricing

11. DEBT – (continued)

of the amounts outstanding under these obligations. The fair value of our outstanding commercial paper and borrowings under our Credit Facilities, the EUS 364-day Credit Facility and the MEP 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 value of our fixed-rate debt obligations was $6.5 billion both for March 31, 2017 and December 31, 2016, respectively. 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.

12. NONCONTROLLING INTERESTS

The following table presents the components of net income (loss) attributable to noncontrolling interests as presented on our consolidated statements of income:

	For the three months ended March 31,	
	2017	2016
	(in millions)	
Eastern Access Interests	$39.5	$51.5
U.S. Mainline Expansion Interests	33.4	26.6
North Dakota Pipeline Company Interests	(1.6)	—
Line 3 Replacement Interests	4.6	—
Midcoast Energy Partners, L.P.	(7.6)	(9.3)
Total	$68.3	$68.8

On January 26, 2017 MEP entered into a definitive merger agreement with our General Partner. On April 27, 2017, this transaction closed and our General Partner acquired, for cash, all of the outstanding publicly held Class A Common Units of MEP. As a result, noncontrolling interest in MEP will be held by our General Partner.

On January 26, 2017, we entered into a joint funding arrangement with our General Partner for the U.S. Line 3 Replacement Program, referred to as the U.S. L3R Program. Under the term of the arrangement, our General Partner will fund 99% and we will fund 1% of the capital costs of the U.S. L3R Program. For further details, refer to Note 17. *Related Party Transactions*.

On January 26, 2017, we exercised our option under the Eastern Access Project joint funding arrangement to acquire an additional 15% interest in the Eastern Access Project, at its book value of approximately $360 million, which is now in service. This transaction reduced noncontrolling interest by approximately $360 million. As of March 31, 2017, we and our General Partner owned 40% and 60% of the partnership interest in Enbridge Energy, Limited Partnership, or the OLP, which we refer to as the EA interest, respectively. For further details, refer to Note 17. *Related Party Transactions*.

13. PARTNERS' CAPITAL

Distribution to Partners

The following table sets forth our distributions, as approved by the board of directors of Enbridge Energy Management, or Enbridge Management, during the three months ended March 31, 2017.

Distribution Declaration Date	Record Date	Distribution Payment Date	Distribution per Unit	Cash Available for Distribution	Amount of Distribution of i-units to i-unit Holders[1]	Retained from General Partner[2]	Distribution of Cash
				(in millions, except per unit amounts)			
January 26, 2017	February 7, 2017	February 14, 2017	$0.5830	$264.8	$47.7	$1.0	$216.1

(1) We issued 2,126,649 i-units to Enbridge Management, the sole owner of our i-units, during 2017 in lieu of cash distributions.

(2) We retained an amount equal to 2% of the i-unit distribution from our General Partner to maintain its 2% general partner interest in us.

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 interests in our consolidated subsidiaries, for the three months ended March 31, 2017 and 2016.

	For the three months ended March 31, 2017	2016
	(in millions)	
Series 1 Preferred interests		
Beginning balance	$1,191.5	$1,186.8
Net income	22.5	22.5
Accretion of discount on preferred units	1.2	1.1
Distribution payable	(22.5)	(22.5)
Ending balance	$1,192.7	$1,187.9
General and limited partner interests		
Beginning balance	$3,124.2	$4,150.8
Net income	65.4	80.0
Distributions	(216.1)	(216.0)
Acquisition of noncontrolling interest in subsidiary	39.1	—
Ending balance	$3,012.6	$4,014.8
Accumulated other comprehensive loss		
Beginning balance	$ (339.3)	$ (370.0)
Changes in fair value of derivative financial instruments reclassified to earnings	10.3	10.0
Changes in fair value of derivative financial instruments recognized in other comprehensive loss	(0.9)	(87.6)
Ending balance	$ (329.9)	$ (447.6)
Noncontrolling interest		
Beginning balance	$3,846.1	$3,944.5
Capital contributions	38.7	54.4
Sale of noncontrolling interest in subsidiary	411.0	—
Acquisition of noncontrolling interest in subsidiary	(360.3)	—
Net income	68.3	68.8
Distributions to noncontrolling interest	(119.1)	(7.6)
Ending balance	$3,884.7	$4,060.1
Total partners' capital at end of period	$7,760.1	$8,815.2

13. PARTNERS' CAPITAL – (continued)

Redemption of Series 1 Preferred Units

On April 27, 2017, we redeemed all of our outstanding Series 1 Preferred Units held by our General Partner at face value of $1.2 billion. We funded the Series 1 Preferred Unit redemption through proceeds from the issuance of 64,308,682 Class A common units to our General Partner at a price of $18.66 per Class A common unit.

In addition, we will repay approximately $357 million in deferred distributions on the Series 1 Preferred Units owed to our General Partner with proceeds from the sale of our natural gas business.

Simplification of Incentive Distributions

On April 27, 2017, a wholly-owned subsidiary of our General Partner irrevocably waived all of its rights associated with its 66.1 million Class D units and 1,000 IDUs, in exchange for the issuance of 1,000 Class F units. For further information refer to Note 3. *Net Income per Limited Partner Unit*.

Curing

Our limited partnership agreement does not permit capital deficits to accumulate in the capital accounts of any limited partner and thus requires that such capital account deficits be ''cured'' by additional allocations from the positive capital accounts of the common units, i-units, and our General Partner, generally on a pro-rata basis. For the three months ended March 31, 2017, the carrying amounts for the capital accounts of the Class A and Class B common units were reduced below zero due to distributions to limited partners in excess of earnings attributable to such limited partners. As a result, the capital balances of the i-units and our General Partner interests were reduced by $21.6 million and $65.0 million, respectively, to cure the applicable deficit balances.

14. DERIVATIVE FINANCIAL INSTRUMENTS AND HEDGING ACTIVITIES

Our net income and cash flows are subject to volatility stemming from changes in interest rates on our variable rate debt obligations and fluctuations in commodity prices of natural gas, NGLs, condensate, crude oil and fractionation margins. Fractionation margins represent the relative difference between the price we receive from NGL and condensate sales and the corresponding commodity costs of natural gas and natural gas liquids we purchase for processing. Our interest rate risk exposure results from changes in interest rates on our variable rate debt and exists at the corporate level where our variable rate debt obligations are issued. Our exposure to commodity price risk exists within each of our segments. 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 interest rates and commodity prices, as well as to reduce volatility in our cash flows. Based on our risk management policies, all of our derivative financial instruments, including those that are not designated for hedge accounting treatment, are employed in connection with an underlying asset, liability or forecasted transaction and are not entered into with the objective of speculating on interest rates or commodity prices. We have hedged a portion of our exposure to the variability in future cash flows associated with the risks discussed above in future periods in accordance with our risk management policies. Our derivative instruments that are designated 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, 2017	December 31, 2016
	(in millions)	
Other current assets	$ 28.3	$ 44.1
Other assets, net	2.1	3.2
Accounts payable and other	(173.0)	(196.3)
Other long-term liabilities	(21.8)	(24.7)
Due to General Partner and affiliates	(0.2)	—
	$(164.6)	$(173.7)

14. DERIVATIVE FINANCIAL INSTRUMENTS AND HEDGING ACTIVITIES – (continued)

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 interest rate contracts, natural gas, NGLs and crude oil sales and purchase contracts.

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

	March 31, 2017	December 31, 2016
	(in millions)	
Counterparty Credit Quality[1]		
AA	$ (74.0)	$ (76.7)
A	(58.6)	(68.2)
Lower than A	(32.0)	(28.8)
	$(164.6)	$(173.7)

[1] As determined by nationally-recognized statistical ratings organizations.

As the net value of our derivative financial instruments has increased in response to changes in forward commodity prices and interest rates, our outstanding financial exposure to third parties has also increased. When credit thresholds are met pursuant to the terms of our International Swaps and Derivatives Association, Inc., or ISDA®, financial contracts, we have the right to require collateral from our counterparties. We include any cash collateral received or posted in the balances listed above. At March 31, 2017 and December 31, 2016, we did not have any cash collateral on our asset exposures. Cash collateral is classified as "Restricted cash" in our consolidated statements of financial position.

We provided letters of credit totaling $125.2 million and $119.5 million relating to our liability exposures pursuant to the margin thresholds in effect at March 31, 2017 and December 31, 2016, respectively, under our ISDA® agreements. 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 interest rate and 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.

In the event that our credit ratings were to decline below the lowest level of investment grade, as determined by Standard & Poor's and Moody's, we would be required to provide additional amounts under our existing letters of credit to meet the requirements of our ISDA® agreements. For example, if our credit ratings had been below the lowest level of investment grade at March 31, 2017, we would have been required to provide additional letters of credit in the amount of $46.7 million related to our positions.

14. DERIVATIVE FINANCIAL INSTRUMENTS AND HEDGING ACTIVITIES – (continued)

At March 31, 2017 and December 31, 2016, we had credit concentrations in the following industry sectors, as presented below:

	March 31, 2017	December 31, 2016
	(in millions)	
United States financial institutions and investment banking entities	$(120.2)	$(128.1)
Non-United States financial institutions	(53.9)	(50.6)
Other	9.5	5.0
	$(164.6)	$(173.7)

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

		Asset Derivatives		Liability Derivatives	
		Fair Value at		Fair Value at	
	Financial Position Location	March 31, 2017	December 31, 2016	March 31, 2017	December 31, 2016
		(in millions)			
Derivatives designated as hedging instruments:[1]					
Interest rate contracts	Accounts payable and other	$ —	$ —	$(143.5)	$(144.0)
Interest rate contracts	Other long-term liabilities	—	—	(20.2)	(21.1)
		—	—	(163.7)	(165.1)
Derivatives not designated as hedging instruments:					
Commodity contracts	Other current assets	28.3	44.1	—	—
Commodity contracts	Other assets	2.1	3.2	—	—
Commodity contracts	Accounts payable and other	—	—	(29.5)	(52.3)
Commodity contracts	Other long-term liabilities	—	—	(1.6)	(3.6)
Commodity contracts	Due to General Partner and affiliates	—	—	(0.2)	—
		30.4	47.3	(31.3)	(55.9)
Total derivative instruments		$30.4	$47.3	$(195.0)	$(221.0)

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

Accumulated Other Comprehensive Income

We record the change in fair value of our highly effective cash flow hedges in AOCI until the derivative financial instruments are settled, at which time they are reclassified to earnings. As of March 31, 2017 and December 31, 2016, we included in AOCI unrecognized losses of approximately $216.1 million and $223.8 million, respectively, associated with derivative financial instruments that qualified for and were classified as cash flow hedges of forecasted transactions that were subsequently de-designated, settled, or terminated. These losses are reclassified to earnings over the periods during which the originally hedged forecasted transactions affect earnings.

14. DERIVATIVE FINANCIAL INSTRUMENTS AND HEDGING ACTIVITIES – (continued)

No commodity hedges were de-designated during the three months ended March 31, 2017 and 2016. We estimate that approximately $41.0 million, representing net losses from our cash flow hedging activities based on pricing and positions at March 31, 2017, 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 months ended March 31, 2017					
Interest rate contracts	$ 1.8	Interest expense	$(10.3)	Interest expense	$(0.3)
Commodity contracts	—	Commodity Costs	—	Commodity Costs	—
Total	$ 1.8		$(10.3)		$(0.3)
For the three months ended March 31, 2016					
Interest rate contracts	$(85.6)	Interest expense	$(10.1)	Interest expense	$(1.9)
Commodity contracts	—	Commodity Costs	0.1	Commodity Costs	—
Total	$(85.6)		$(10.0)		$(1.9)

(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	
	2017	2016
	(in millions)	
Balance at January 1	$(339.3)	$(370.0)
Other comprehensive loss before reclassifications	(0.9)	(87.6)
Amounts reclassified from AOCI[1]	10.3	10.0
Net other comprehensive income (loss)	9.4	(77.6)
Balance at March 31	$(329.9)	$(447.6)

(1) 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 months ended March 31,	
	2017	2016
	(in millions)	
Losses on cash flow hedges:		
Interest Rate Contracts[1]	$10.3	$10.0
Total Reclassifications from AOCI	$10.3	$10.0

(1) Loss reported within "Interest expense, net" in the consolidated statements of income.

14. DERIVATIVE FINANCIAL INSTRUMENTS AND HEDGING ACTIVITIES – (continued)

Effect of Derivative Instruments on Consolidated Statements of Income

Derivatives Not Designated as Hedging Instruments	Location of Gain or (Loss) Recognized in Earnings	For the three months ended March 31, 2017	2016
		Amount of Gain or (Loss) Recognized in Earnings(1)(2)	
		(in millions)	
Commodity contracts	Commodity sales	$ (3.5)	$(2.4)
Commodity contracts	Commodity sales – affiliate	(0.2)	—
Commodity contracts	Transportation and other services(3)	1.7	0.8
Commodity contracts	Commodity costs(4)	16.2	1.8
Total		$14.2	$ 0.2

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

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

(3) Includes settlement gains of $2.5 million for the three months ended March 31, 2016.

(4) Includes settlement gains of $6.6 million and $26.5 million for the three months ended March 31, 2017 and 2016, 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 govern 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, 2017				
	Gross Amount of Recognized Assets	Gross Amount Offset in the Statement of Financial Position	Net Amount of Assets Presented in the Statement of Financial Position	Gross Amount Not Offset in the Statement of Financial Position	Net Amount
			(in millions)		
Description:					
Derivatives	$30.4	$—	$30.4	$(21.0)	$9.4

	As of December 31, 2016				
	Gross Amount of Recognized Assets	Gross Amount Offset in the Statement of Financial Position	Net Amount of Assets Presented in the Statement of Financial Position	Gross Amount Not Offset in the Statement of Financial Position	Net Amount
			(in millions)		
Description:					
Derivatives	$47.3	$—	$47.3	$(40.2)	$7.1

14. DERIVATIVE FINANCIAL INSTRUMENTS AND HEDGING ACTIVITIES – (continued)

Offsetting of Financial Liabilities and Derivative Liabilities

	As of March 31, 2017				
	Gross Amount of Recognized Liabilities	Gross Amount Offset in the Statement of Financial Position	Net Amount of Liabilities Presented in the Statement of Financial Position	Gross Amount Not Offset in the Statement of Financial Position	Net Amount
			(in millions)		
Description:					
Derivatives . . .	$(195.0)	$—	$(195.0)	$21.0	$(174.0)

	As of December 31, 2016				
	Gross Amount of Recognized Liabilities	Gross Amount Offset in the Statement of Financial Position	Net Amount of Liabilities Presented in the Statement of Financial Position	Gross Amount Not Offset in the Statement of Financial Position	Net Amount
			(in millions)		
Description:					
Derivatives . . .	$(221.0)	$—	$(221.0)	$40.2	$(180.8)

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, 2017 and December 31, 2016. 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, 2017				December 31, 2016			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
				(in millions)				
Interest rate contracts . . .	$—	$(163.7)	$ —	$(163.7)	$—	$(165.1)	$ —	$(165.1)
Commodity contracts:								
Financial	—	—	(6.4)	(6.4)	—	(4.1)	(0.1)	(4.2)
Physical	—	—	5.6	5.6	—	—	2.6	2.6
Commodity options	—	—	(0.1)	(0.1)	—	—	(7.0)	(7.0)
Total	$—	$(163.7)	$(0.9)	$(164.6)	$—	$(169.2)	$(4.5)	$(173.7)

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: (i) quoted prices for assets and liabilities; (ii) time value; and (iii) 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.

14. DERIVATIVE FINANCIAL INSTRUMENTS AND HEDGING ACTIVITIES – (continued)

Qualitative Information about Level 3 Fair Value Measurements

Data from pricing services and published indices are used to measure the fair value of our Level 3 derivative instruments 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, crude and power) are forward commodity prices. The significant unobservable inputs used in determining the fair value measurement of options are price and volatility. Forward commodity price in isolation has a direct relationship to the fair value of a commodity contract in a long position and an inverse relationship to a commodity contract in a short position. Volatility has a direct relationship to the fair value of an option contract. 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 has an inverse relationship to the fair value of our derivative contracts.

Quantitative Information About Level 3 Fair Value Measurements

Contract Type	Fair Value at March 31, 2017	Valuation Technique	Unobservable Input	Range[(1)] Lowest	Range[(1)] Highest	Range[(1)] Weighted Average	Units
	(in millions)						
Commodity Contracts – Financial							
Natural Gas	$ 1.5	Market Approach	Forward Natural Gas Price	$ 2.30	$ 3.57	$ 3.14	MMBtu
NGLs	(7.9)	Market Approach	Forward NGL Price	$ 0.24	$ 1.15	$ 0.57	Gal
Commodity Contracts – Physical							
Natural Gas	0.5	Market Approach	Forward Natural Gas Price	$ 2.62	$ 3.42	$ 3.10	MMBtu
Crude Oil	(0.6)	Market Approach	Forward Crude Oil Price	$39.94	$52.00	$48.57	Bbl
NGLs	5.7	Market Approach	Forward NGL Price	$ 0.23	$ 1.29	$ 0.57	Gal
Commodity Options							
Natural Gas, Crude Oil and NGLs	(0.1)	Option Model	Option Volatility	22%	100%	49%	
Total Fair Value	$(0.9)						

(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.

Contract Type	Fair Value at December 31, 2016[(2)]	Valuation Technique	Unobservable Input	Range[(1)] Lowest	Range[(1)] Highest	Range[(1)] Weighted Average	Units
	(in millions)						
Commodity Contracts – Financial							
Natural Gas	$ 4.7	Market Approach	Forward Natural Gas Price	$ 3.18	$ 3.93	$ 3.58	MMBtu
NGLs	(4.8)	Market Approach	Forward NGL Price	$ 0.27	$ 1.23	$ 0.64	Gal
Commodity Contracts – Physical							
Natural Gas	0.7	Market Approach	Forward Natural Gas Price	$ 2.72	$ 4.16	$ 3.49	MMBtu
Crude Oil	(1.2)	Market Approach	Forward Crude Oil Price	$39.21	$55.62	$52.00	Bbl
NGLs	3.1	Market Approach	Forward NGL Price	$ 0.27	$ 1.31	$ 0.48	Gal
Commodity Options							
Natural Gas, Crude Oil and NGLs	(7.0)	Option Model	Option Volatility	22%	33%	25%	
Total Fair Value	$(4.5)						

(1) Prices are in dollars per MMBtu for natural gas, Gal for NGLs and Bbl for crude oil.

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

14. DERIVATIVE FINANCIAL INSTRUMENTS AND HEDGING ACTIVITIES – (continued)

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, 2017 to March 31, 2017. 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, 2017	$(0.1)	$ 2.6	$(7.0)	$ (4.5)
Transfer in (out) of Level 3[1]	—	—	—	—
Gains or losses included in earnings:				
Reported in Commodity sales	—	(10.5)	—	(10.5)
Reported in Commodity costs	2.3	11.6	5.1	19.0
Gains or losses included in other comprehensive income:				
Reported in other comprehensive income (loss), net of tax	—	—	—	—
Purchases, issuances, sales and settlements:				
Purchases	—	—	—	—
Sales	—	—	—	—
Settlements[2]	(8.6)	1.9	1.8	(4.9)
Ending balance as of March 31, 2017	$(6.4)	$ 5.6	$(0.1)	$ (0.9)
Amounts reported in Commodity sales	$ —	$ (3.8)	$ —	$ (3.8)
Amount of changes in net assets attributable to the change in derivative gains or losses related to assets and liabilities still held at the reporting date:				
Reported in Commodity sales	$ —	$ (6.1)	$ —	$ (6.1)
Reported in Commodity sales – affiliate	$ —	$ (0.2)	$ —	$ (0.2)
Reported in Commodity costs	$ 1.3	$ 9.3	$ 5.4	$ 16.0

(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.

14. DERIVATIVE FINANCIAL INSTRUMENTS AND HEDGING ACTIVITIES – (continued)

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, 2017 and December 31, 2016.

	At March 31, 2017						At December 31, 2016	
			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 2017								
Swaps								
Receive variable/pay fixed	Natural Gas	3,820,000	$ 3.14	$ 3.00	$0.6	$(0.1)	$ 2.6	$ —
	NGL	3,504,500	$27.56	$28.16	$1.4	$(3.4)	$21.4	$ —
	Crude Oil	592,250	$51.51	$61.33	$0.4	$(6.2)	$ 0.9	$ (5.6)
Receive fixed/pay variable	NGL	4,390,250	$26.85	$28.18	$2.3	$(8.1)	$ —	$(27.5)
	Crude Oil	953,700	$57.71	$51.66	$6.8	$(1.0)	$ 5.7	$ (3.8)
Receive variable/pay variable	Natural Gas	21,085,000	$ 3.10	$ 3.05	$1.5	$(0.6)	$ 2.5	$ (0.4)
Physical Contracts								
Receive variable/pay fixed	Natural Gas	121,500	$ 2.68	$ 2.67	$ —	$ —	$ —	$ —
	NGL	1,084,520	$14.53	$10.50	$6.3	$ —	$ 0.9	$ —
Receive fixed/pay variable	Natural Gas	114,000	$ 2.71	$ 2.70	$ —	$ —	$ —	$ —
	NGL	1,514,234	$18.14	$19.25	$0.3	$(3.7)	$ —	$ (1.2)
Receive variable/pay variable	Natural Gas	48,471,230	$ 3.06	$ 3.06	$0.4	$ —	$ 0.6	$ —
	NGL	11,067,927	$23.46	$23.12	$4.5	$(0.8)	$ 2.6	$ (0.6)
	Crude Oil	254,824	$46.57	$49.12	$0.3	$(1.0)	$ 0.7	$ (2.0)
Portion of contracts maturing in 2018								
Swaps								
Receive variable/pay variable	Natural Gas	10,130,000	$ 2.97	$ 2.96	$0.3	$(0.3)	$ —	$ —
Physical Contracts								
Receive fixed/pay variable	NGL	110,238	$29.28	$30.27	$ —	$(2.7)	$ —	$ —
Receive variable/pay variable	Natural Gas	5,400,000	$ 3.33	$ 3.32	$0.1	$ —	$ 0.1	$ —
	NGL	9,753,179	$21.82	$21.63	$1.9	$(0.1)	$ 1.4	$ —

(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, 2017 and December 31, 2016, respectively, discounted using the swap rate for the respective periods to consider the time value of money. Fair values exclude credit valuation adjustment gains of approximately $0.1 million at March 31, 2017 and no gains at December 31, 2016, as well as cash collateral received.

The following table provides summarized information about the fair values of expected cash flows of our outstanding commodity options at March 31, 2017 and December 31, 2016.

	At March 31, 2017						At December 31, 2016	
					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 2017								
Puts (purchased)	NGL	1,237,500	$25.90	$32.13	$2.8	$ —	$3.4	$ —
	Crude Oil	481,250	$59.86	$51.69	$4.9	$ —	$4.6	$ —
Calls (written)	NGL	1,237,500	$30.06	$32.13	$ —	$(7.1)	$ —	$(13.4)
	Crude Oil	481,250	$68.19	$51.69	$ —	$(0.4)	$ —	$ (1.1)
Portion of option contracts maturing in 2018								
Puts (purchased)	Crude Oil	91,250	$42.00	$51.83	$0.2	$ —	$0.2	$ —
Calls (written)	Crude Oil	91,250	$51.75	$51.83	$ —	$(0.5)	$ —	$ (0.8)

(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, 2017 and December 31, 2016, respectively, discounted using the swap rate for the respective periods to consider the time value of money. Fair values exclude credit valuation adjustment gains with no gains at March 31, 2017 and approximately $0.1 million at December 31, 2016, as well as cash collateral received.

14. DERIVATIVE FINANCIAL INSTRUMENTS AND HEDGING ACTIVITIES – (continued)

Fair Value Measurements of Interest Rate Derivatives

We enter into interest rate swaps, caps and derivative financial instruments with similar characteristics to manage the cash flow associated with future interest rate movements on our indebtedness. The following table provides information about our current interest rate derivatives for the specified periods.

				Fair Value[2] at	
Date of Maturity & Contract Type	Accounting Treatment	Notional	Average Fixed Rate[1]	March 31, 2017	December 31, 2016
			(dollars in millions)		
Contracts maturing in 2018					
Interest Rate Swaps – Pay Fixed	Cash Flow Hedge	$ 810	2.24%	$ (6.3)	$ (9.4)
Contracts maturing in 2019					
Interest Rate Swaps – Pay Fixed	Cash Flow Hedge	$ 620	2.96%	$ (7.2)	$ (7.3)
Contracts settling prior to maturity					
2017 – Pre-issuance Hedges	Cash Flow Hedge	$1,000	4.07%	$(137.7)	$(136.2)
2018 – Pre-issuance Hedges	Cash Flow Hedge	$ 350	3.08%	$ (13.3)	$ (13.1)

(1) Interest rate derivative contracts are based on the one-month or three-month London Interbank Offered Rate, or LIBOR.

(2) The fair value is determined from quoted market prices at March 31, 2017 and December 31, 2016, 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 adjustment gains of approximately $0.8 million and $1.2 million at March 31, 2017 and December 31, 2016, respectively.

15. 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 franchise tax laws by the State of Texas that apply to entities organized as partnerships, and which is based upon many but not all items included in net income.

We compute our income tax expense by applying a Texas state franchise tax rate to modified gross margin. Our Texas state franchise tax rate was 0.3% and 0.4% for the three months ended March 31, 2017 and 2016, respectively.

At March 31, 2017 and December 31, 2016, we had no current income tax obligation and a current income tax refund receivable of $1.0 million, respectively, in ‘‘Property and other taxes payable’’ on our consolidated statements of financial position. In addition, at March 31, 2017 and December 31, 2016, we included a deferred income tax payable of $20.5 million and $20.0 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.

16. SUPPLEMENTAL CASH FLOWS INFORMATION

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

	For the three months ended March 31,	
	2017	2016
	(in millions)	
Total capital expenditures (excluding ‘‘Investments in joint ventures’’)	$ 97.6	$282.0
Decrease in construction payables	46.9	107.7
Cash used for additions to property, plant and equipment	$144.5	$389.7

16. SUPPLEMENTAL CASH FLOWS INFORMATION – (continued)

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

	For the three months ended March 31,	
	2017	2016
	(in millions)	
Receivables, trade and other	$ (8.0)	$ 9.8
Due from General Partner and affiliates	(11.7)	(32.6)
Accrued receivables	(20.8)	35.6
Inventory	(9.1)	19.8
Current and long-term other assets	22.7	5.8
Due to General Partner and affiliates	(76.0)	(30.3)
Accounts payable and other	27.9	(81.4)
Environmental liabilities	(6.5)	(5.0)
Accrued purchases	2.8	(32.1)
Interest payable	18.0	23.6
Property and other taxes payable	(2.0)	(3.2)
Changes in operating assets and liabilities	$(62.7)	$(90.0)

17. RELATED PARTY TRANSACTIONS

Administrative and Workforce Related Services

We do not directly employ any of the individuals responsible for managing or operating our business nor do we have any directors. Enbridge and its affiliates provide management and we obtain managerial, administrative, operational and workforce related services from our General Partner, Enbridge Management and affiliates of Enbridge pursuant to service agreements among our General Partner, Enbridge Management, affiliates of Enbridge, and us. Pursuant to these service agreements, we have agreed to reimburse our General Partner, Enbridge Management and affiliates of Enbridge, for the cost of managerial, administrative, operational and director services they provide to us. Where directly attributable, the cost of all compensation, benefits expenses and employer expenses for these employees are charged directly by Enbridge to the appropriate affiliate. Enbridge does not record any profit or margin for the administrative and operational services charged to us.

The affiliate amounts incurred by us for services received pursuant to the services agreements are reflected in ‘‘Operating and administrative — affiliate’’ on our consolidated statements of income.

Enbridge and its affiliates allocated direct workforce costs to us for our construction projects of $3.7 million and $9.7 million for the three months ended March 31, 2017 and 2016, 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 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 ‘‘Commodity sales — affiliate’’ on our consolidated statements of income. We also record operating revenues in our Liquids segment for storage, transportation and terminalling services we provide to affiliates, which are presented in ‘‘Transportation and other services — affiliate’’ on our consolidated statements of income.

We also purchase NGLs and crude oil from Enbridge and its affiliates for sale to third parties at market prices on the date of purchase. Purchases of NGLs and crude oil from Enbridge and its affiliates are presented in ‘‘Commodity costs — affiliate’’ on our consolidated statements of income.

Related Party Transactions with Joint Ventures

We incurred $8.2 million and $5.4 million for the three months ended March 31, 2017 and 2016, respectively, of pipeline transportation and demand fees from Texas Express NGL system for our Natural Gas business. These expenses are included in ‘‘Commodity costs — affiliate’’ on our consolidated statements of income.

17. RELATED PARTY TRANSACTIONS – (continued)

Our Natural Gas segment has made commitments to transport up to 120,000 barrels per day, or Bpd, of NGLs on the Texas Express NGL system by 2022. Our transportation commitment increased from the commitment level of 50,000 Bpd at March 31, 2017 to 86,000 Bpd effective April 1, 2017, resulting in an average of 75,000 Bpd for the year.

Sale of Accounts Receivable

We and certain of our subsidiaries were parties to a receivables purchase agreement, which we refer to as the Receivables Agreement, with an indirect, wholly-owned subsidiary of Enbridge. As part of the Receivables Agreement, we sold and derecognized receivables of $965.8 million and $901.6 million for the three months ended March 31, 2017 and 2016, respectively. We received cash proceeds of $965.2 million and $901.2 million for the three months ended March 31, 2017 and 2016, respectively.

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 ‘‘Operating and administrative — affiliate’’ expense in our consolidated statements of income. For the three months ended March 31, 2017 and 2016, the expense stemming from the discount on the receivables sold was not material.

As of March 31, 2017 and December 31, 2016, we had $14.9 million and $24.5 million, respectively, in ‘‘Restricted cash’’ on our consolidated statements of financial position, for cash collections related to sold and derecognized receivables that have yet to be remitted to the Enbridge subsidiary. As of March 31, 2017 and December 31, 2016, outstanding receivables of $275.2 million and $354.7 million, respectively, which had been sold and derecognized, had not been collected on behalf of the Enbridge subsidiary.

On April 27, 2017, we terminated our Receivables Agreement with the indirect, wholly-owned subsidiary of Enbridge in exchange for a one-time $5 million payment to us.

Financing Transactions with Affiliates

EUS Credit Agreement

In connection with the Bakken Transaction, on February 15, 2017, we entered into an unsecured revolving 364-day credit agreement with EUS, or the EUS Credit Agreement. The EUS Credit Agreement is a committed senior unsecured revolving credit facility that permits aggregate borrowings of up to, at any one time outstanding for the purpose of funding the Bakken Transaction, $1.5 billion, (i) on a revolving basis for a 364-day period and (ii) for a 364-day term on a non-revolving basis following the expiration of the revolving period; provided that the EUS Credit Agreement will mature on the date any project financing is completed. Loans under the EUS Credit Agreement accrue interest based, at our election, on either the Eurocurrency rate or a base rate, in each case, plus an applicable margin. A facility fee will accrue at the applicable margin rate, which is based on our non-credit-enhanced, senior unsecured long-term debt rating at the applicable time.

In addition, on or before the maturity date, we may repay or prepay all, but not less than all, of the aggregate outstanding principal balance of the loans under the EUS Credit Agreement by payment-in-kind of our entire direct and indirect interest in the Bakken Pipeline System. As of March 31, 2017, we had $1.5 billion in outstanding borrowing under this facility.

The EUS Credit Agreement also includes representations, warranties, financial covenants and events of default that are consistent with those in the EUS 364-Day Credit Facility. Amounts borrowed under the EUS Credit Agreement bear interest at rates that accrue interest, at our election, based on either the Eurocurrency rate or a base rate, in each case, plus an applicable margin. This is consistent with the interest rates set forth in the EUS 364-Day Credit Facility.

On April 27, 2017, in connection with finalizing the joint funding arrangement with our General Partner for the Bakken Pipeline System, we repaid the facility in full. Refer to *Joint Funding Arrangement for Bakken Pipeline System*.

17. RELATED PARTY TRANSACTIONS – (continued)

EUS 364-day Credit Facility

We are party to an unsecured revolving 364-day credit agreement, which we refer to as the EUS 364-day Credit Facility, with EUS. The EUS 364-day Credit Facility is a committed senior unsecured revolving credit facility that permits aggregate borrowings of up to, at any one time outstanding, $750 million, (i) on a revolving basis for a 364-day period and (ii) for a 364-day term on a non-revolving basis following the expiration of the revolving period. Loans under the EUS 364-day Credit Facility accrue interest, at our election, based on either the Eurocurrency rate or a base rate, in each case, plus an applicable margin. The EUS 364-day Credit Facility terminates on July 25, 2017. At that time, we may elect to convert any outstanding loans to term loans, which would mature on July 24, 2018. As of March 31, 2017, we had no outstanding borrowings under this facility.

The commitment under the EUS 364-day Credit Facility may be permanently reduced by EUS, from time to time, by up to an amount equal to the net cash proceeds to us from the sale by us of (i) debt or equity securities in a registered public offering, or (ii) limited partnership interests in Midcoast Operating to MEP.

Distribution from MEP

The following table presents distributions paid by MEP during the three months ended March 31, 2017, to its public Class A common unitholders, representing the noncontrolling interest in MEP, and to us for our ownership of Class A common units.

Distribution Declaration Date	Distribution Payment Date	Amount Paid to EEP	Amount Paid to Noncontrolling Interest	Total MEP Distribution
			(in millions)	
January 26, 2017	February 14, 2017	$8.9	$7.6	$16.5

Financial Support Agreement

At March 31, 2017, we had no letters of credit outstanding and utilized $29.9 million of guarantees to Midcoast Operating under a Financial Support Agreement with Midcoast Operating. At December 31, 2016, we had no letters of credit outstanding and utilized $39.9 million of guarantees to Midcoast Operating under this agreement.

Joint Funding Arrangement for Bakken Pipeline System

On April 27, 2017, our Board of Directors finalized the joint funding arrangement with our General Partner for the Bakken Pipeline System. Under the terms of the arrangement, our General Partner owns 75% and we own 25% of the Bakken Pipeline System, with a five year option for us to increase our interest by 20% at net book value. With the finalization of the joint funding arrangement, we repaid the outstanding balance of $1.5 billion under the EUS Credit Agreement.

Joint Funding Arrangement for Line 3 Replacement

On January 26, 2017, our Board of Directors approved a joint funding arrangement with our General Partner for the U.S. L3R Program. Under the terms of the arrangement, our General Partner will fund 99% and we will fund 1% of the capital cost of the U.S. L3R Program, with an option for us to increase our interest up to 40% in the U.S. portion at book value at any time up to four years after the project goes into service. Our General Partner paid us approximately $450.0 million for its 99% interest in the project, including our share of the construction costs to date and other incremental amounts. The carrying amount of our 99% interest in the project at the transaction date was $411.0 million and was recorded as an increase to noncontrolling interest. The $39.1 million difference between the cash received and the carrying amount was recorded as an increase to the capital accounts of our common units, i-units, and General Partner interest on a pro-rata basis.

Our General Partner made equity contributions totaling $18.8 million to the OLP for the three months ended March 31, 2017, to fund its equity portion of the construction costs associated with the U.S. L3R Program.

Joint Funding Arrangement for Eastern Access Projects

We have a joint funding arrangement with the General Partner that established an additional series of partnership interest in the OLP, which we refer to as the EA interest. The EA interests were created to finance the Eastern Access Projects to increase access to refineries in the U.S. Upper Midwest and in Ontario, Canada for light

17. RELATED PARTY TRANSACTIONS – (continued)

crude oil produced in western Canada and the United States. Until January 26, 2017, our General Partner and we jointly funded the Eastern Access Projects at 75% and 25%, respectively. On January 26, 2017, we exercised our option under the Eastern Access joint funding arrangement to acquire an additional 15% interest in the Eastern Access Projects, at its book value of approximately $360 million, which is now in service. This transaction reduced noncontrolling interest by approximately $360 million. As of March 31, 2017, we and our General Partner owned 40% and 60% of the EA interests, respectively.

Our General Partner made equity contributions totaling $5.6 million and $7.2 million to the OLP for the three months ended March 31, 2017 and 2016, respectively, to fund its equity portion of the construction costs associated with the Eastern Access Projects.

Distribution to Series EA Interests

The following table presents distributions paid by the OLP during the three months ended March 31, 2017, to our General Partner and its affiliate, representing the noncontrolling interest in the Series EA, and to us, as the holders of the Series EA general and limited partner interests. The distributions were declared by the board of directors of Enbridge Management, acting on behalf of Enbridge Pipelines (Lakehead), L.L.C., the managing general partner of the OLP and the Series EA interests.

Distribution Declaration Date	Distribution Payment Date	Amount Paid to EEP	Amount Paid to Noncontrolling Interest	Total Series EA Distribution
			(in millions)	
January 26, 2017	February 14, 2017	$22.9	$68.8	$91.7

Joint Funding Arrangement for U.S. Mainline Expansion Projects

The OLP also has a series of partnership interests, which we refer to as the ME interests. The ME interests were created to finance the Mainline Expansion Projects to increase access to the markets of North Dakota and western Canada for light oil production on our Lakehead System between Neche, North Dakota and Superior, Wisconsin. Our General Partner owns 75% of the ME interests, and the projects are jointly funded by our General Partner at 75% and us at 25%, under the Mainline Expansion joint funding arrangement, which is similar to the Eastern Access joint funding arrangement.

Our General Partner has made equity contributions totaling $14.5 million and $42.8 million to the OLP for the three months ended March 31, 2017, and 2016, respectively, to fund its equity portion of the construction costs associated with the Mainline Expansion Projects.

Distribution to Series ME Interests

The following table presents distributions paid by the OLP during the three months ended March 31, 2017, to our General Partner and its affiliate, representing the noncontrolling interest in the Series ME, and to us, as the holders of the Series ME general and limited partner interests. The distributions were declared by the board of directors of Enbridge Management, acting on behalf of Enbridge Pipelines (Lakehead), L.L.C., the managing general partner of the OLP and the Series ME interests.

Distribution Declaration Date	Distribution Payment Date	Amount Paid to EEP	Amount Paid to Noncontrolling Interest	Total Series ME Distribution
			(in millions)	
January 26, 2017	February 14, 2017	$14.2	$42.7	$56.9

18. 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 liquid hydrocarbon and natural gas pipeline operations, 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 other potentially responsible parties, we will be responsible for payment of liabilities arising from environmental incidents associated with the operating activities of our liquids and natural gas businesses. Our General Partner has agreed to indemnify us from and against any costs relating to environmental liabilities associated with the Lakehead system assets prior to the transfer of these assets to us in 1991. This excludes any liabilities resulting from a change in laws after such transfer. We continue to voluntarily investigate 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, 2017 and December 31, 2016, our consolidated statements of financial position included \$97.5 million and \$99.9 million, respectively, in ‘‘Environmental liabilities,’’ and \$57.1 million and \$50.8 million, respectively, in ‘‘Other long-term liabilities,’’ that we have accrued for costs to address remediation of contaminated sites, asbestos containing materials, management of hazardous waste material disposal, outstanding air quality measures for certain of our liquids and natural gas assets and penalties we have been or expect to be assessed.

Lakehead Line 6B Crude Oil Release

On July 26, 2010, a release of crude oil on Line 6B of our Lakehead system was reported near Marshall, Michigan. We estimate that approximately 20,000 barrels of crude oil were leaked at the site, a portion of which reached the Kalamazoo River via Talmadge Creek, a waterway that feeds the Kalamazoo River. The released crude oil affected approximately 38 miles of shoreline along the Talmadge Creek and Kalamazoo River waterways, including residential areas, businesses, farmland and marshland between Marshall and downstream of Battle Creek, Michigan.

We continue to evaluate the need for additional remediation activities and are performing the necessary restoration and monitoring of the areas affected by the Line 6B crude oil release. All the initiatives we are undertaking in the monitoring and restoration phase are intended to restore the crude oil release area to the satisfaction of the appropriate regulatory authorities.

As of March 31, 2017, our cumulative cost estimate for the Line 6B crude oil release remains at \$1.2 billion. For purposes of estimating our expected losses associated with the Line 6B crude oil release, we have included those costs that we considered probable and that could be reasonably estimated at March 31, 2017. Our estimates exclude: (i) amounts we have capitalized, (ii) any claims associated with the release that may later become evident, (iii) amounts recoverable under insurance, and (iv) fines and penalties from other governmental agencies except as described in the *Fines and Penalties* section below. Our assumptions include, where applicable, estimates of the expected number of days the associated services will be required and rates that we have obtained from contracts negotiated for the respective service and equipment providers. As we receive invoices for the actual personnel, equipment and services, our estimates will continue to be further refined. Our estimates also consider currently available facts, existing technology and presently enacted laws and regulations. These amounts also consider our and other companies’ prior experience remediating contaminated sites and data released by government organizations. Despite the efforts we have made to ensure the reasonableness of our estimates, changes to the recorded amounts associated with this release are possible as more reliable information becomes available. We continue to have the potential of incurring additional costs in connection with this crude oil release due to variations in any or all of the categories described above, including modified or revised requirements from regulatory agencies, in addition to fines and penalties as well as expenditures associated with litigation and settlement of claims.

The components underlying our cumulative estimated loss for the cleanup, remediation and restoration associated with the Line 6B crude oil release, the majority of which have been paid, include the following:

18. COMMITMENTS AND CONTINGENCIES – (continued)

	(in millions)
Response personnel and equipment	$ 547.3
Environmental consultants	224.3
Professional, regulatory, fines and penalties and other	443.4
Total	$1,215.0

For the three months ended March 31, 2017 and 2016, we made payments of $2.0 million and $8.4 million, respectively, for costs associated with the Line 6B crude oil release. As of March 31, 2017 and December 31, 2016, we had a remaining estimated liability of $136.4 million and $138.8 million, respectively.

Line 6B Fines and Penalties

At March 31, 2017, our total estimated costs related to the Line 6B crude oil release include $68.5 million in fines and penalties. Of this amount, $61.0 million relates to civil penalties under the Clean Water Act of the United States, which we have fully reserved in our contingency accrual but have not yet paid.

Consent Decree

On July 20, 2016, a Consent Decree was filed with the United States District Court for the Western District of Michigan, Southern Division, or the Court. The Consent Decree is our signed settlement agreement with the U.S. Environmental Protection Agency and the U.S. Department of Justice regarding Lines 6A and 6B crude oil releases. Pursuant to the Consent Decree, we will pay $62.0 million in civil penalties: $61.0 million in respect of Line 6B and $1.0 million in respect of a separate 2010 crude oil release on Line 6A. The Consent Decree will take effect upon approval by the Court.

In addition to the monetary fines and penalties, the Consent Decree calls for replacement of Line 3, which we initiated in 2014 and is currently under regulatory review in the State of Minnesota; refer to Item 2. *Management's Discussion and Analysis of Financial Condition and Results of Operations — Line 3 Replacement Program* for further details. The Consent Decree contains a variety of injunctive measures, including, but not limited to, enhancements to our comprehensive in-line inspection (ILI)-based spill prevention program; enhanced measures to protect the Straits of Mackinac; improved leak detection requirements; installation of new valves to control product loss in the event of an incident; continued enhancement of control room operations; and improved spill response capabilities. Collectively, these measures build on continuous improvements we have implemented since 2010 to our leak detection program, control center operations, and emergency response program. We estimate the total cost of these measures to be approximately $110.0 million, most of which is already incorporated into existing long-term capital investment and operational expense planning and guidance. Compliance with the terms of the Consent Decree is not expected to materially impact our overall financial performance.

Insurance

We are included in the comprehensive insurance program that is maintained by Enbridge for its subsidiaries and affiliates. On May 1 of each year, our insurance program is renewed and includes commercial liability insurance coverage that is consistent with coverage considered customary for our industry and includes coverage for environmental incidents such as those we have incurred for the crude oil release from Line 6B, excluding costs for fines and penalties.

Enbridge, together with us and its other affiliates, are covered under its comprehensive property and liability insurance programs, under which we are insured through April 30, 2018, with a liability program aggregate limit of $940.0 million, which includes sudden and accidental pollution liability. In the unlikely event that multiple insurable incidents which in aggregate exceed coverage limits occur within the same insurance period, the total insurance coverage will be allocated among the Enbridge entities on an equitable basis based on an insurance allocation agreement we have entered into with Enbridge, and other Enbridge subsidiaries.

A majority of the costs incurred for the July 2010 Line 6B crude oil release, other than fines and penalties, are covered by the insurance policies that expired on April 30, 2011, which had an aggregate limit of $650.0 million for pollution liability for Enbridge and its affiliates. Including our remediation spending through March 31, 2017, costs

18. COMMITMENTS AND CONTINGENCIES – (continued)

related to Line 6B exceeded the limits of the coverage available under these insurance policies. Through March 31, 2017, we have recorded total insurance recoveries of $547.0 million for the Line 6B crude oil release, out of the $650.0 million aggregate limit.

In March 2013, we and Enbridge filed a lawsuit against the insurers of $145.0 million of coverage, as one particular insurer disputed our recovery eligibility for costs related to our claim on the Line 6B crude oil release and the other remaining insurers asserted that their payment was predicated on the outcome of our recovery with that insurer. We received a partial recovery payment of $42.0 million from the other remaining insurers and amended our lawsuit such that it includes only one insurer.

Of the remaining $103.0 million coverage limit, $85.0 million was the subject matter of a lawsuit Enbridge filed against one particular insurer described above. In March 2015, Enbridge reached agreement with that insurer to submit the $85.0 million claim to binding arbitration. On May 2, 2017, the arbitration panel issued a decision that was not favorable to Enbridge. As a result, we are unlikely to receive any additional insurance recoveries in connection with the Line 6B crude oil release.

Legal and Regulatory Proceedings

We are a participant in various legal and regulatory proceedings arising in the ordinary course of business. Some of these proceedings are covered, in whole or in part, by insurance. We are also directly, or indirectly, subject to challenges by special interest groups to regulatory approvals and permits for certain of our expansion projects.

A number of governmental agencies and regulators have initiated investigations into the Line 6B crude oil release. Two actions or claims are pending against us and our affiliates in state courts in connection with the Line 6B crude oil release. Based on the current status of these cases, we do not expect the outcome of these actions to be material to our results of operations or financial condition.

We have accrued a provision for future legal costs and probable losses associated with the Line 6B crude oil release as described above in this footnote.

19. SUBSEQUENT EVENTS

Sale of Natural Gas Business

On April 27, 2017, we entered into a definitive agreement with the General Partner to sell all of our ownership interests in our natural gas business. Under the agreement, we will sell our 48.4% limited partnership interest in Midcoast Operating, our 51.9% limited partnership interest in MEP, and our 100% interest in MEP's general partner for $2.15 billion, which amount includes cash proceeds of $1.31 billion and $840 million of outstanding indebtedness at MEP.

Redemption of Series 1 Preferred Units

On April 27, 2017, we redeemed all of our outstanding Series 1 Preferred Units held by our General Partner at face value of $1.2 billion. We funded the Series 1 Preferred Unit redemption through proceeds from the issuance of 64,308,682 Class A common units to our General Partner at a price of $18.66 per Class A common unit.

In addition, we will repay approximately $357 million in deferred distributions on the Series 1 Preferred Units owed to our General Partner with proceeds from the sale of our natural gas business.

Simplification of Incentive Distributions

On April 27, 2017, a wholly-owned subsidiary of our General Partner irrevocably waived all of its rights associated with its 66.1 million Class D units and 1,000 IDUs, in exchange for the issuance of 1,000 Class F units. For further information refer to Note 3. *Net Income per Limited Partner Unit*.

Joint Funding Arrangement for Bakken Pipeline System

On April 27, 2017, our Board of Directors finalized the joint funding arrangement with our General Partner for the Bakken Pipeline System. Under the terms of the arrangement, our General Partner owns 75% and we own 25%

19. SUBSEQUENT EVENTS – (continued)

of the Bakken Pipeline System, with a five year option for us to increase our interest by 20% at net book value. With the finalization of the joint funding arrangement, we repaid the outstanding balance of $1.5 billion under the EUS Credit Agreement.

Distribution to Partners

On April 27, 2017, the board of directors of Enbridge Management declared a distribution payable to our partners on May 15, 2017. The distribution will be paid to unitholders of record as of May 8, 2017 of our available cash of $159.6 million at March 31, 2017, or $0.35 per limited partner unit. Of this distribution, $129.6 million will be paid in cash, $29.4 million will be distributed in i-units to our i-unitholder, Enbridge Management, and due to the i-unit distribution, $0.6 million will be retained from our General Partner from amounts otherwise distributable to it in respect of its general partner interest and limited partner interest to maintain its 2% general partner interest. Distributions to be paid include (i) distributions to the additional 64,308,682 Class A common units issued to the General Partner on April 27, 2017 and (ii) incentive distributions to the 1,000 Class F units. No distributions were made to the Class D units or the IDUs.

Distribution to Series EA Interests

On April 27, 2017, the board of directors of Enbridge Management, acting on behalf of Enbridge Pipelines (Lakehead) L.L.C., the managing general partner of the OLP and a holder of the Series EA interests, declared a distribution payable to the holders of the Series EA general and limited partner interests. The OLP will pay $62.0 million to the noncontrolling interest in the Series EA, while $29.3 million will be paid to us.

Distribution to Series ME Interests

On April 27, 2017, the board of directors of Enbridge Management, acting on behalf of Enbridge Pipelines (Lakehead) L.L.C., the managing general partner of the OLP and a holder of the Series ME interests, declared a distribution payable to the holders of the Series ME general and limited partner interests. The OLP will pay $38.0 million to the noncontrolling interest in the Series ME, while $12.7 million will be paid to us.

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* of this report and in conjunction with the audited consolidated financial statements and accompanying footnotes in our Annual Report on Form 10-K for the year ended December 31, 2016, as filed with the Securities and Exchange Commission, or the SEC, on February 17, 2017.

Strategic Review

Our ultimate parent, Enbridge, recently completed a merger with Spectra Energy Corp. Enbridge had indicated that as part of the integration of the two companies, its U.S. sponsored vehicles, including us, would be reviewed in context of the combined enterprise.

On April 28, 2017, we announced the conclusion of our strategic review. We and our General Partner have taken the following actions to strengthen our financial position and outlook:

- The reduction of our quarterly distribution from $0.583 per unit to $0.35 per unit or from $2.33 per unit to $1.40 per unit on an annualized basis;
- The entry into a definitive agreement to sell all of our interests in our natural gas business to our General Partner for $2.15 billion, including cash consideration of $1.31 billion and $840 million of existing outstanding indebtedness at MEP. A portion of these proceeds will be used for other restructuring actions including the repayment of deferred distributions on our Series 1 Preferred Units, as discussed below. Refer to *Future Prospects Update for Natural Gas* for further information;
- The finalization of our joint funding arrangement for our investment in the Bakken Pipeline System in which our General Partner owns 75% interest, and we own a 25% interest with an option to acquire an additional 20% interest from our General Partner at net book value. Refer to *Future Prospects Update for Liquids — Bakken Pipeline System* for further information;
- The redemption of our outstanding Series 1 Preferred Units held by the General Partner at face value of $1.2 billion which was funded with the proceeds from the issuance of Class A common units to our General Partner;
- The entry into an agreement to repay the $357 million deferred distribution balance owning to our General Partner with the proceeds from the sale of our interest in our natural gas business following the closing of that sale; and
- The simplification of our capital structure and complexity and modification of our incentive distribution rights through the irrevocable waiver by a wholly-owned subsidiary of our General Partner of all of that subsidiary's 66.1 million Class D units and 1,000 IDUs in consideration for issuance of a new class of units, Class F units. These units are entitled to (i) 13% of all distributions of available cash in excess of $0.295 per unit, but less than $0.35 per unit, and (ii) 23% of all distributions of available cash in excess of $0.35 per unit.

Previously, on January 26, 2017, our Board of Directors approved three initial strengthening actions to alleviate short-term capital expenditure requirements and enhance our cash flows as follows:

- We approved a joint funding arrangement with our General Partner for the U.S. L3R Program whereby our General Partner paid us approximately $450 million for a 99% interest in the project, including our share of the construction costs to date and other incremental amounts. Refer to *Future Prospects Updates for Liquids — Line 3 Replacement Program*.
- We acquired an additional 15% interest in the Eastern Access Project, at its book value of approximately $360 million, which is now in service. We utilized the funds received from the joint funding arrangement for the U.S. L3R Program to exercise our option under the Eastern Access joint funding arrangement.
- MEP entered into the merger agreement with our General Partner, whereby, on April 27, 2017, our General Partner acquired, for cash, all of the outstanding publicly held Class A common units of MEP. Refer to *Future Prospects Updates for Natural Gas* for further details.

RESULTS OF OPERATIONS — OVERVIEW

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

- Interstate pipeline transportation and storage of crude oil and liquid petroleum; and
- Gathering, treating, processing and transportation of natural gas and natural gas liquids, or NGLs, through pipelines and related facilities, along with supply, transportation and sales services, including purchasing and selling natural gas and NGLs.

We conduct our business through two business segments: Liquids and Natural Gas. Our Liquids segment includes the operations of our Lakehead, Mid-Continent and North Dakota systems. These systems largely consist of FERC regulated interstate crude oil and liquid petroleum pipelines, gathering systems and storage facilities. The Lakehead system, together with the Enbridge system in Canada, forms the longest liquid petroleum pipeline system in the world. Our Liquids systems generate revenues primarily from charging shippers a rate per barrel to gather, transport and store crude oil and liquid petroleum.

Our Natural Gas segment includes natural gas and NGL gathering and transportation pipeline systems, natural gas processing and treating facilities, condensate stabilizers and an NGL fractionation facility. Moreover, our Natural Gas segment also provides supply, transmission, storage and sales services to producers and wholesale customers on our natural gas gathering, transmission and customer pipelines, as well as other interconnected pipeline systems. Revenues for our Natural Gas segment 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. Segment gross margin is derived from the compensation we receive from customers in the form of fees or commodities we receive for providing services in addition to the proceeds we receive for sales of natural gas, NGLs and condensate to affiliates and third-parties.

On April 27, 2017, we entered into a definitive merger with the General Partner, whereby the General Partner will acquire all of our ownership interest in our natural gas business through the acquisition of 48.4% interest in Midcoast Operating, L.P., all of our ownership interests in Midcoast Holdings, L.L.C., and all of our limited partnership interests in MEP.

The following table reflects our operating income by business segment and corporate charges for the three months ended March 31, 2017 and 2016.

	For the three months ended ended March 31,	
	2017	2016
	(in millions)	
Operating income (loss)		
Liquids	$ 271.2	$ 301.4
Natural Gas	(17.9)	(29.9)
Other	(6.0)	(3.5)
Total operating income	247.3	268.0
Interest expense	(106.8)	(112.9)
Allowance for equity used during construction	10.3	12.3
Other income	8.1	7.5
Income before income tax expense	158.9	174.9
Income tax expense	(1.5)	(2.5)
Net income	157.4	172.4
Less: Net income attributable to:		
Noncontrolling interest	68.3	68.8
Series 1 preferred unit distributions	22.5	22.5
Accretion of discount on Series 1 preferred units	1.2	1.1
Net income attributable to general and limited partner ownership interests in Enbridge Energy Partners, L.P.	$ 65.4	$ 80.0

Highlights

Liquids

Our Liquids segment operating income decreased $30.2 million for the three months ended March 31, 2017, as compared to the same period in 2016, primarily as a result of lower operating revenues due to lower average rates and lower volumes on the North Dakota system. The decrease in operating revenue is partially offset by lower environmental costs. Volumes on our Lakehead system increased in 2017, when compared to the same period in 2016, from assets placed into service in 2016 including portions of the Eastern Access, Mainline Expansion and other projects.

Natural Gas

Our Natural Gas segment operating loss decreased $12.0 million for the three months ended March 31, 2017, respectively, as compared to the same period in 2016. The decrease in operating loss was primarily the result of lower operating and administrative costs period over period. Further contributing to the decrease in operating loss was an increase in segment gross margin due to increased non-cash mark-to-market gains in the current period compared to the same period in 2016. The decrease in the operating loss was offset by lower volumes. The average daily volumes of our major systems for the three months ended March 31, 2017, decreased by approximately 298,000 MMBtu/d, or 16%, as compared to the same period in 2016 and the average NGL production for the three months ended March 31, 2017, decreased 11,838 Bpd, or 16%, as compared to the same period in 2016.

Derivative Transactions and Hedging Activities

Contractual arrangements expose us to market risks associated with changes in (i) commodity prices where we receive crude oil, natural gas or NGLs in return for the services we provide or where we purchase natural gas or NGLs and (ii) interest rates on our variable rate debt. 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 and interest rates, 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 or interest rates. Derivative financial instruments that do not receive hedge accounting under the provisions of authoritative accounting guidance 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 receive hedge accounting in our consolidated statements of income as follows:

- Liquids segment commodity-based derivatives — "Transportation and other services"
- Natural Gas segment commodity-based derivatives — "Commodity sales" and "Commodity costs"
- Interest rate derivatives — "Interest expense"

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 months ended March 31,	
	2017	2016
	(in millions)	
Liquids segment:		
Non-qualified hedges	$ 1.7	$ (1.7)
Natural Gas segment:		
Non-qualified hedges	5.9	(27.1)
Commodity derivative fair value net gains (losses)	7.6	(28.8)
Other:		
Interest rate hedge ineffectiveness	(0.3)	(1.9)
Derivative fair value net gains (losses)	$ 7.3	$(30.7)

RESULTS OF OPERATIONS — BY SEGMENT

Liquids

The following tables set forth the operating results and statistics of our Liquids segment assets for the periods presented:

	For the three months ended March 31,	
	2017	2016
	(in millions)	
Operating Results:		
Operating revenue	$604.7	$629.7
Operating expenses:		
Environmental costs, net of recoveries	10.3	16.9
Operating and administrative	140.0	137.2
Power	74.5	72.8
Depreciation and amortization	108.7	101.4
Total operating expenses	333.5	328.3
Operating income	$271.2	$301.4
Operating Statistics		
Lakehead system:		
United States[(1)]	2,057	2,073
Canada[(1)]	691	662
Total Lakehead system delivery volumes[(1)]	2,748	2,735
Barrel miles (billions)	191	190
Average haul (miles)	773	764
Mid-Continent system delivery volumes[(1)]	145	168
North Dakota system:		
Trunkline[(1)]	334	402
Gathering[(1)]	—	—
Total North Dakota system delivery volumes[(1)]	334	402
Total Liquids segment delivery volumes[(1)]	3,227	3,305

(1) Average Bpd in thousands.

Three months ended March 31, 2017, compared with the three months ended March 31, 2016

Operating income of our Liquids segment for the three months ended March 31, 2017, decreased $30.2 million, as compared to the same period in 2016, due to the reasons discussed below.

Operating revenue of our Liquids segment decreased $25.0 million for the three months ended March 31, 2017, as compared to the same period in 2016. The overall decrease in operating revenue is primarily attributable to the following:

Average daily delivery volumes on our Lakehead system increased; however, operating revenue for the three months ended March 31, 2017, decreased $4.8 million, as compared to the same period in 2016. The decrease in operating revenue was due to lower average toll rates, as a result of lower index rates adopted during the second quarter of 2016, which contributed to $4.2 million of the $4.8 million decrease. Further contributing to the decrease in operating revenue period over period were $9.1 million of surcharges recognized in the first quarter of 2016 related to the recovery of hydrostatic testing costs on Line 2B, for which recovery was completed in 2016. No such surcharges were recognized in the same period of 2017. The decrease in operating revenue was partially offset by an increase of $8.5 million due to higher surcharge revenue for additional projects placed into service in 2016. The surcharge revenue was partially offset by lower surcharges due to the impact of a depreciation study which came into effect in the fourth quarter of 2016.

Operating revenue on the North Dakota system decreased $13.3 million for the three months ended March 31, 2017, as compared to the same period in 2016, primarily due to the expiration of the Phase 5 looping and Phase 6 surcharges, as well as lower rail revenue. Operating revenue decreased $8.9 million period over period due to the expiration of the Phase 5 and Phase 6 toll surcharges at December 31, 2016. Average daily delivery volumes decreased by 68,000 Bpd due to lower throughput on the North Dakota system to the Berthold rail facility as contracts on the Berthold rail facility expired. This resulted in a decrease of $4.5 million in operating revenue for the rail facility.

Operating revenue on the Mid-Continent system decreased $7.1 million for the three months ended March 31, 2017, as compared to the same period in 2016. The decrease in operating revenue was due primarily to the absence of one month of revenue from the Ozark Pipeline System, which was sold on March 1, 2017, as well as a $2.3 million decrease due to lower storage and terminalling revenue for the Cushing system. Operational cost savings related to the sale of the Ozark Pipeline System amounted to $3.0 million for the month of March 2017.

Environmental costs, net of recoveries, decreased $6.6 million for the three months ended March 31, 2017, when compared with the same period in 2016. This decrease is due to a $15.0 million cost accrual for estimated fines and penalties associated with the Line 6B crude oil release in the first quarter of 2016. During the three months ended March 31, 2017, there were no cost accruals for the Line 6B crude oil release. The decrease was partially offset by a $9.7 million increase in environmental remediation costs related to a release on the Ozark Pipeline System on January 14, 2017.

Operating and administrative expenses increased $2.8 million for the three months ended March 31, 2017, when compared to the same period in 2016, primarily due to previously-committed Sandpiper expenses incurred of $4.0 million, as well as severance costs related to workforce reductions of $3.8 million. These increases were partially offset by the gain on disposal of the Ozark Pipeline System, as well as operational cost savings related to the sale, as described above.

The increase in depreciation expense of $7.3 million for the three months ended March 31, 2017, when compared to the same period in 2016, is directly attributable to additional assets placed into service in 2016.

Future Prospects Update for Liquids

We currently have a multi-billion dollar growth program underway, with projects coming into service in 2019, in addition to options to increase our economic interest in projects that are jointly funded by Enbridge and us. On January 27, 2017, we announced two initial strengthening actions are being undertaken in our liquids business, which together alleviate short-term capital expenditure requirements and enhance our cash flows.

- Our Board of Directors approved a joint funding arrangement with our General Partner for the U.S. L3R Program. Through this arrangement, we maintain a strong cash-generating significant opportunity to invest in a strategic growth project, while obtaining relief from funding requirements during the construction period. Refer to *Line 3 Replacement Program* below for further details.
- Additionally, we exercised our option under the Eastern Access joint funding arrangement to acquire an additional 15% interest in the Eastern Access Projects, at its book value of approximately $360 million, which is now in service.

Recent Developments

<u>Bakken Pipeline System</u>

On February 15, 2017, our joint venture with MPC and MarEn closed the Bakken Transaction with Bakken Holdings, an affiliate of Energy Transfer Partners, L.P. and Sunoco Logistics Partners L.P., to, among other things, acquire a 49% equity interest in BPI. BPI owns 75% of the Bakken Pipeline System. Under this arrangement, we and MPC would indirectly hold 75% and 25%, respectively, of the joint venture's 49% interest in BPI. The purchase price of our effective 27.6% interest in the Bakken Pipeline was $1.5 billion.

We initially funded the $1.5 billion acquisition through a Credit Agreement provided by EUS, which is an affiliate of our General Partner. On April 27, 2017, our Board of Directors finalized the joint funding arrangement with our General Partner for our effective interest in the Bakken Pipeline System. Under the terms of the arrangement, our General Partner owns 75% and we own 25%. We also have a five-year option to acquire an additional 20% interest in the Bakken Pipeline System at net book value. With the finalization of this joint funding arrangement, we repaid the $1.5 billion outstanding under the EUS Credit Agreement.

The Bakken Pipeline System, which consists of the Dakota Access Pipeline, or DAPL, and the Energy Transfer Crude Oil Pipeline, or ETCOP, projects, will transport crude oil from the Bakken formation in North Dakota to markets in eastern the Petroleum Administration for Defense Districts, or PADD II, and the U.S. Gulf Coast. DAPL consists of 1,172 miles of 30-inch pipeline from the Bakken/Three Forks production area in North Dakota to Patoka, Illinois. It is expected to initially deliver in excess of 470,000 Bpd of crude oil and has the potential to be expanded to 570,000 Bpd. ETCOP consists of 62 miles of new 30-inch diameter pipe, 686 miles of converted 30-inch diameter pipe, and 40 miles of converted 24-inch diameter pipe from Patoka, Illinois to Nederland, Texas. The construction of the Bakken Pipeline System is in the final stages of commissioning and is expected to begin generating cash flow during the second quarter of 2017.

Renewal of Line 5 Easement

On January 4, 2017, the Tribal Council of the Bad River Band of Lake Superior Tribe of Chippewa Indians, or the Band, issued a press release indicating that the Band had passed a resolution not to renew its interest in certain Line 5 easements through the Bad River Reservation. Line 5 is included within the Lakehead system. The Band's resolution calls for decommissioning and removal of the pipeline from all Bad River tribal lands and watershed and could impact Enbridge's ability to operate the pipeline on the Reservation. Since the Band passed the resolution, the parties have agreed to ongoing discussions with the objective of understanding and resolving the Band's concerns on a long term basis.

Expansion Projects

The table and discussion below summarizes our commercially secured projects for the Liquids segment, which will be placed into service in future periods:

Projects	Total Estimated Capital Costs	Expected In-Service Date	Funding
	(in millions)		
Line 3 Replacement Program[(1)]	$2,600	2019	Joint[(2)]
U.S. Mainline Expansions:			
Line 61 (1,200,000 Bpd capacity)[(4)]	435	2019	Joint[(3)]

(1) As discussed under *Line 3 Replacement Program* below, the expected cost and in-service date of this project are under review by us in light of the schedule for regulatory review and approval communicated by the Minnesota Public Utilities Commission, or MNPUC, on October 28, 2016.

(2) As discussed under *Line 3 Replacement Program* below, the Conflicts Committee and Board of Directors approved a joint funding arrangement with the General Partner for the U.S. L3R Program. The General Partner will fund 99% and we will fund 1% of the capital cost of the U.S. L3R Program.

(3) Jointly funded 25% by us and 75% by our General Partner under the Mainline Expansion Joint Funding Arrangement. Estimated capital costs are presented at 100% before our General Partner's contributions.

(4) Estimated in-service date will be adjusted to coincide with the in-service date of the U.S. L3R Program and the impact of cost to be reviewed. In 2015, we completed the expansion of pipeline capacity to 950,000 Bpd.

Line 3 Replacement Program

In 2014, we and Enbridge jointly announced that shipper support was received to replace portions of the existing 1,031-mile Line 3 pipeline on the Canadian Mainline/Lakehead system between Hardisty, Alberta, Canada and Superior, Wisconsin. Our portion of the U.S. L3R Program includes replacing 358 miles from the U.S./Canadian border at Neche, North Dakota to Superior, Wisconsin. The U.S. L3R Program will support the safety and operational reliability of the system, enhance flexibility, allow us and Enbridge to optimize throughput on the mainline system, and will restore approximately 370,000 Bpd capacity from Western Canada into Superior, Wisconsin.

We are in the process of obtaining the appropriate permits for constructing the U.S. L3R Program in Minnesota. The project requires both a Certificate of Need, or Certificate, and an approval of the pipeline's route, or Route Permit, from the MNPUC. The MNPUC found both the Certificate and Route Permit applications for the U.S. L3R Program through Minnesota to be complete. On February 1, 2016, the MNPUC issued a written order requiring the Minnesota Department of Commerce, or DOC, to prepare a final Environmental Impact Statement, or EIS, before the Certificate and Route Permit processes commence. We currently expect the DOC's draft EIS by mid-May 2017.

We will recover our costs based on our existing Facilities Surcharge Mechanism, or FSM, with the initial term being 15 years. For purposes of the toll surcharge, the agreement specifies a 30 year recovery of the capital based on a cost-of-service methodology.

On January 26, 2017, our Board of Directors approved a joint funding arrangement with our General Partner for the U.S. L3R Program. Under the terms of the arrangement, our General Partner and we will fund 99% and 1% of the capital cost of the U.S. L3R Program, respectively. We have an option to increase our interest up to 40% in the U.S. portion at book value at any time up to four years after the project goes into service. Our General Partner paid us approximately $450 million for its 99% interest in the project, including our share of the construction costs to date and other incremental amounts.

U.S. Mainline Expansion

We and Enbridge have invested in a Light Oil Market Access Program to expand access to markets for growing volumes of light oil production. This program responds to significant developments with respect to supply of light oil from U.S. north central formations and western Canada, as well as refinery demand for light oil in the U.S. Midwest and eastern Canada. The remaining projects in the Light Oil Market Access Program will further expand capacity on our U.S. mainline system and provide additional access to U.S. Midwestern refineries.

The U.S. Mainline Expansion Projects include a series of crude oil pipeline expansion projects for our mainline pipeline system between Neche, North Dakota, and Flanagan, Illinois. These projects include the expansion of our existing 36-inch diameter Alberta Clipper pipeline, or Line 67 and our existing 42-inch diameter Southern Access pipeline, or Line 61, and the construction of Line 78, a twin of the Spearhead North pipeline, or Line 62. The expansion on Line 67 and construction of Line 78 were completed during 2015.

The Line 67 pipeline expansion remains subject to the receipt of an amendment to the current Presidential border crossing permit to allow for operation of the Line 67 pipeline at its currently planned operating capacity of 800,000 Bpd. On February 10, 2017, the United States Department of State, or Department, the agency that is responsible for issuing permits for cross-border pipelines pursuant to a delegation of authority by the President under an Executive Order, issued a Draft Supplemental Environmental Impact Statement, or Draft SEIS, which determined that there were no significant adverse environmental impacts from the planned capacity increase. The public comment period on the Draft SEIS closed on March 27, 2017. The Department will review all received comments and prepare a Final SEIS. The Executive Order also requires that the Department initiate a 90-day inter-agency consultation period to solicit comments from certain other federal agencies on whether the Line 67 expansion will serve the national interest. The inter-agency consultation period commenced on March 28, 2017. Following issuance of the Final SEIS and completion of the inter-agency consultation process, the Administration will make a decision and issue a Presidential Permit if it finds that doing so is in the national interest. The Administration's decision is expected later in the year.

In 2015, we completed the Line 61 expansion, between Superior, Wisconsin and Flanagan, Illinois, which increased the pipeline capacity to 950,000 Bpd. The remaining work includes an expansion phase to increase the pipeline capacity to 1,200,000 Bpd at an expected cost of approximately $435 million. In conjunction with shippers, a decision was made to delay the in-service date of this remaining expansion phase to 2019 to align more closely with the anticipated in-service date for the U.S. L3R Program.

We operate the U.S. Mainline Expansions Projects on a cost-of-service basis. These Projects are jointly funded 75% by our General Partner and 25% by us under the Mainline Expansion Joint Funding Arrangement. We have the option to increase our economic interest held up to 15% at cost.

Natural Gas

The following tables set forth the operating results of our Natural Gas segment and approximate average daily volumes of natural gas throughput and NGLs produced on our major systems for the periods presented.

	For the three months ended March 31,	
	2017	2016
	(in millions)	
Operating revenues	$ 574.0	$ 431.9
Commodity costs	487.8	348.0
Segment gross margin	86.2	83.9
Operating and administrative	66.6	74.3
Depreciation and amortization	37.5	39.5
Operating expenses	104.1	113.8
Operating loss	(17.9)	(29.9)
Other income	8.1	7.1
Net loss	$ (9.8)	$ (22.8)
Operating Statistics (MMBtu/d)		
East Texas	848,000	948,000
Anadarko	495,000	652,000
North Texas	175,000	216,000
Total	1,518,000	1,816,000
NGL Production (Bpd)	61,661	73,499

Three months ended March 31, 2017, compared with the three months ended March 31, 2016

The operating loss of our Natural Gas segment for the three months ended March 31, 2017, decreased $12.0 million, as compared to the same period in 2016, primarily as a result of lower operating and administrative costs in the 2017 period, as well as an increase in segment gross margin.

Segment gross margin increased $2.3 million for the three months ended March 31, 2017, as compared to the same period in 2016. The increase was attributable to non-cash, mark-to-market gains offset by declines in volumes and prices as described below. Our natural gas segment recognized non-cash, mark-to-market gains of $5.9 million for the three months ended March 31, 2017, as compared to losses of $27.1 million during the same period in 2016. The resulting increase in segment gross margin of $33.0 million period over period is primarily due to gains resulting from the reversal of lower unrealized mark-to-market gains previously recognized for the three months ended March 31, 2017 as compared to the same period in 2016 as these underlying transactions have settled.

The increase in segment gross margin due to non-cash, mark-to-market gains was offset by the following factors:

- Decrease in segment gross margin of $15.9 million for the three months ended March 31, 2017, as compared to the same period in 2016, due to lower commodity prices, net of hedges, as well as a decrease in processing margins along with a decline in NGL volumes and associated keep-whole volumes in the Anadarko and East Texas regions;
- Decrease in segment gross margin of approximately $11.1 million for the three months ended March 31, 2017, as compared to the same period in 2016, due to reduced natural gas throughput. The average daily volumes of our major systems decreased by approximately 298,000 MMBtu/d, or 16%, for the three months ended March 31, 2017, as compared to the same period in 2016. The average NGL production for the three months ended March 31, 2017, decreased 11,838 Bpd, or 16%, as compared to the same period in 2016. The decreases in volumes were primarily attributable to the continued low commodity price environment for natural gas, condensate and NGLs, which resulted in reductions in drilling activity by producers in the areas we operate;
- Decrease in segment gross margin of $3.0 million for the three months ended March 31, 2017, as compared to the same period in 2016, due to a decrease in storage margins as a result of the sale of liquids product inventory at lower prevailing market prices relative to the cost of product inventory; and

Operating and administrative costs decreased $7.7 million for the three months ended March 31, 2017, as compared to the same period in 2016. The decrease was attributable to $12.4 million in cost savings as a result of workforce reductions, lower property taxes, repairs and maintenance costs and the sale of certain trucks, trailers and related facilities during the third quarter of 2016. Decreases in operating and administrative costs were partially offset by gains of $5.6 million recorded during the first quarter of 2016 to recognize return of escrow funds and a reversal of a contingent liability related to an acquisition. No such gains were recognized during the first quarter of 2017. Decreases in operating costs were also offset by severance costs of $2.0 million due to additional workforce reduction actions that occurred in the first quarter of 2017.

Future Prospects Update for Natural Gas

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 continue to remain low. The depressed commodity price environment is the most significant factor for reduced drilling activity and low volumes in the basins in which we operate. Due to the extended low commodity price environment, we expect drilling activity to remain low and as a result, we expect to see declining volumes on our systems in 2017.

We have a hedging program in place to assist in mitigating our direct commodity risk from contracts in which we are paid in commodities for our services. However, we are not fully hedged, and our hedge positions for 2017 are significantly lower than they were in 2016. We have hedged approximately 80% and 5% of our direct forecasted commodity cash flow exposure for 2017 and 2018, respectively. Our condensate and NGL hedge prices for 2017 are approximately 20% and 30% lower than 2016, respectively. See *Liquidity and Capital Resources — Derivative Activities* below. Despite our hedging program, we still bear indirect commodity price exposure as lower drilling activity impacts the volumes on our systems as well as direct commodity price exposure for unhedged commodity positions. We expect this indirect impact on our volumes to fluctuate depending on future price movements. In addition, our transportation commitments increased from the commitment level of 50,000 Bpd at March 31, 2017 to 86,000 Bpd effective April 1, 2017, resulting in an average of 75,000 Bpd for the year.

In light of the extended low commodity price environment, we have been evaluating opportunities to strengthen our natural gas business. On April 27, 2017, we entered into a definitive agreement with our General Partner to sell all of our ownership interests in our natural gas business. Our General Partner will acquire our 48.4% ownership in Midcoast Operating, L.P., our 51.9% interest in MEP and our 100% interest in MEP's general partner for $2.15 billion, which includes cash proceeds of $1.31 billion and the outstanding indebtedness at MEP will continue to be an ongoing obligation of MEP. The closing of this transaction is subject to customary closing conditions, including expiration of termination of the waiting period under the Hart-Scott-Rodino Antitrust Improvements Act.

On January 26, 2017, MEP entered into a definitive merger agreement, referred to as the Merger Agreement, with our General Partner. On April 27, 2017, pursuant to the Merger Agreement, our General Partner acquired, for cash, all of the outstanding publicly held common units of MEP at a price of $8 per common unit for an aggregate transaction value of $170.2 million. The public interest acquired by our General Partner represents an approximate 25% effective interest in our natural gas gathering and processing business.

Other

Other consists of interest expense, allowance for equity used during construction and other costs such as income taxes, which are not allocated to the business segments.

	For the three months ended March 31,	
	2017	2016
	(in millions)	
Operating Results:		
Operating and administrative expenses	$ 6.0	$ 3.5
Operating loss	(6.0)	(3.5)
Interest expense, net	(106.8)	(112.9)
Allowance for equity used during construction	10.3	12.3
Other income	—	0.4
Loss before income tax expense	(102.5)	(103.7)
Income tax expense	(1.5)	(2.5)
Net loss	$(104.0)	$(106.2)

Three months ended March 31, 2017, compared with three months ended March 31, 2016

The $2.2 million decrease in our segment net loss for the three months ended March 31, 2017, as compared to the same period in 2016, was mainly attributable to a decrease in interest expense of $6.1 million due to higher capitalized interest of $8.2 million, period over period, primarily due to our investment in the Bakken Pipeline System. This decrease was partially offset by increased interest expense from higher average outstanding debt balance, including additional borrowings from our General Partner, during the three months ended March 31, 2017.

Further, AEDC decreased $2.0 million for the three months ended March 31, 2017, as compared to the same period in 2016, due to reduction in outstanding capital projects in which AEDC is being recognized.

LIQUIDITY AND CAPITAL RESOURCES

General

Our primary operating cash requirements consist of normal operating expenses, maintenance capital expenditures, funding requirements associated with environmental costs, distributions to our partners and payments associated with our risk management activities. We expect to fund our current and future short-term cash requirements for these items from our operating cash flows supplemented as necessary by issuances of commercial paper and borrowings under our Credit Facilities. Margin requirements associated with our derivative transactions are generally supported by letters of credit issued under our Credit Facilities.

Our current business strategy includes developing and expanding our existing business through organic growth and targeted acquisitions, in addition to the strategies and actions taken as discussed above under *Strategic Review*.

We expect to initially fund our long-term cash requirements for expansion projects and acquisitions, as well as retire our maturing and callable debt, first from operating cash flows and then from issuances of commercial paper and borrowings on our Credit Facilities. We expect to obtain permanent financing as needed through the issuance of additional equity and debt securities, which we will use to repay amounts initially drawn to fund these activities, although there can be no assurance that such financings will be available on favorable terms, if at all.

In the past, when we had attractive growth opportunities in excess of our own capital raising capabilities, our General Partner provided supplementary funding, or participated directly in projects, to enable us to undertake such opportunities. If in the future we have attractive growth opportunities that exceed capital raising capabilities, we could seek similar arrangements from our General Partner, but there can be no assurance that this funding can be obtained.

Available Liquidity

Our primary source of short-term liquidity is provided by our $1.5 billion commercial paper program, which is supported by our $2.0 billion multi-year unsecured revolving credit facility, which we refer to as the Credit Facility, and our $625.0 million credit agreement, which we refer to as the 364-Day Credit Facility. We refer to the 364-Day Credit Facility and the Credit Facility as our Credit Facilities. We access our commercial paper program primarily to provide temporary financing for our operating activities, capital expenditures and acquisitions when the interest rates available to us for commercial paper are more favorable than the rates available under our Credit Facilities. At March 31, 2017, we had approximately $960.8 million in available credit under the terms of our Credit Facilities.

We are also party to an unsecured revolving 364-day credit agreement with EUS. The EUS 364-day Credit Facility is a committed senior unsecured revolving credit facility that permits aggregate borrowings of up to, at any one time outstanding, $750.0 million. For the three months ended March 31, 2017, we made gross repayments of approximately $750.0 million under the terms of the EUS 364-day Credit Facility.

For further details regarding our commercial paper program, our Credit Facilities, the EUS 364-day Credit Facility and the EUS Credit Agreement, refer to Item 1. *Financial Statements*, Note 11. *Debt*.

As of March 31, 2017, although we had a working capital deficit of approximately $0.9 billion, excluding $1.5 billion in outstanding borrowings under the EUS Credit Agreement, we had approximately $1.3 billion of consolidated liquidity to meet our ongoing operational, investing and financing needs as described above, as well as the funding requirements associated with the environmental remediation costs resulting from the crude oil release on Line 6B. We used the EUS Credit Agreement to finance our investment of the Bakken Pipeline System. On April 27, 2017, finalized the joint funding arrangement with our General Partner. As a result of the finalization of this joint funding arrangement, we repaid the outstanding balance of $1.5 billion under the EUS Credit Agreement. For further details on the joint funding arrangement, refer to *Joint Funding Arrangements*.

The following table sets forth the consolidated liquidity available to us at March 31, 2017.

	EEP	MEP	Total
		(in millions)	
Cash and cash equivalents	$ 104.3	$ —	$ 104.3
Total commitments under EEP's Credit Facilities	2,625.0	—	2,625.0
Total commitments under the EUS 364-day Credit Facility	750.0	—	750.0
Total commitments under the EUS Credit Agreement	1,500.0	—	1,500.0
Total commitments under MEP's Credit Agreement	—	670.0	670.0
Less: Amounts outstanding under EEP's Credit Facilities	1,525.0	—	1,525.0
Amounts outstanding under MEP's Credit Agreement	—	440.0	440.0
Amounts outstanding under the EUS Credit Agreement	1,500.0	—	1,500.0
Principal amount of commercial paper outstanding	762.4	—	762.4
Letters of credit outstanding	126.8	—	126.8
Total	$1,065.1	$230.0	$1,295.1

MEP Credit Agreement

MEP, Midcoast Operating, and their domestic material subsidiaries are party to a senior revolving credit facility, which we refer to as the MEP Credit Agreement, which permits aggregate borrowings of up to $670.0 million, at any one time outstanding. The original term of the MEP Credit Agreement was three years with an initial maturity date of November 13, 2016, subject to four one-year requests for extensions at the lenders' discretion, two of which we have utilized. The MEP Credit Agreement's current maturity date is September 30, 2018; however, $25.0 million of commitments expire on September 30, 2017.

The MEP Credit Agreement also requires compliance with two financial covenants. MEP must not permit the ratio of consolidated funded debt to pro forma Earnings Before Interest, Taxes, Depreciation and Amortization, or EBITDA (the total leverage ratio), of MEP and its consolidated subsidiaries (including Midcoast Operating), as of the end of any applicable four-quarter period, to exceed 5.00 to 1.00, or 5.50 to 1.00 during acquisition periods. MEP also must maintain (on a consolidated basis), as of the end of each applicable four-quarter period, a ratio of pro forma EBITDA to consolidated interest expense for such four-quarter period then ended of at least 2.50 to 1.00.

Each of MEP's domestic material subsidiaries has unconditionally guaranteed all existing and future indebtedness and liabilities of the borrowers arising under the MEP Credit Agreement and other loan documents, and each co-borrower has guaranteed all such indebtedness and liabilities of the other co-borrower. The MEP Credit Agreement is unsecured but security will be provided upon occurrence of any of the following: (i) for two consecutive quarters, the total leverage ratio as described below, exceeds 4.25 to 1.00, or 4.75 to 1.00 during acquisition periods, (ii) uncured breach to certain terms and conditions of the MEP Credit Agreement and (iii) obtaining a non-investment grade initial debt rating from either Standard and Poor's or Moody's.

At March 31, 2017, MEP was in compliance or deemed in compliance with the terms of its financial covenants in the MEP Credit Agreement. The total leverage ratio of MEP and its consolidated subsidiaries with respect to the four-quarter period ending March 31, 2017, was 5.14x. On May 9, 2017, MEP exercised its right to issue sufficient Class A common units to the General Partner to result in a revised total leverage ratio of 4.58x, and thus, pursuant to the terms of the Credit Agreement, is deemed in compliance with the total leverage ratio for the quarter ending March 31, 2017. Due to the extended low commodity price environment and the potential implications on MEP's results of operations, it is likely that MEP may not be able to meet the total leverage ratio financial covenant at some point during 2017 without further action on its part. If this were to occur, we have indicated to MEP that we expect to provide them certain additional capital contributions to prevent a default under the MEP Credit Agreement. MEP would also seek a waiver from its lenders, pursue refinancing of the amounts outstanding under the MEP Credit Agreement, or seek to take other action to prevent a default under the MEP Credit Agreement, although there can be no assurance that MEP will secure any such preventative actions. Failure to comply with one or both of the financial covenants may result in the occurrence of an event of default under the MEP Credit Agreement, which would result in a cross-default under the note purchase agreement relating to MEP's senior notes. If an event of default were to occur, the lenders could, among other things, terminate their commitments under the MEP Credit Agreement, demand immediate payment of all amounts borrowed by MEP and Midcoast Operating, trigger the springing liens, and require adequate security or collateral for all outstanding letters of credit outstanding under the facility. In addition, MEP and Midcoast Operating are restricted under the MEP Credit Agreement from making distributions to us in certain circumstances involving certain defaults under that agreement or any event of default under that agreement. Furthermore, a default under the MEP Credit Agreement or Purchase Agreement would limit our ability to receive payment of amounts that may be owed to us under the Financial Support Agreement. Any inability of MEP or Midcoast Operating to make distributions, or of Midcoast Operating to repay its indebtedness to us, could reduce our cash flows and affect our results of operations.

On April 27, 2017, we entered into a definitive agreement with our General Partner to sell our ownership interest in our natural gas business. As part of the of the agreement our General Partner will acquire our 48.4% interest in Midcoast Operating, our 51.9% interest in MEP and our 100% interest in MEP's General Partner. MEP's outstanding debt obligation under the MEP Credit Agreement will not be repaid at the closing of the transaction, rather it will remain outstanding and continue as an ongoing obligation of MEP.

MEP Senior Notes

MEP has $400.0 million of notes consisting of three tranches of senior notes: $75.0 million of 3.56% Series A Senior Notes due in 2019; $175.0 million of 4.04% Series B Senior Notes due in 2021; and $150.0 million of 4.42% Series C Senior Notes due in 2024, collectively the Notes. The Notes were issued pursuant to a Note Purchase Agreement, or the Purchase Agreement, between MEP and the purchasers named therein. The Notes and all other obligations under the Purchase Agreement are unconditionally guaranteed by each of MEP's domestic material subsidiaries pursuant to a guaranty agreement. Until such time as MEP obtain an investment grade rating from either Moody's or Standard and Poor's and upon certain trigger events, MEP and the guarantors will grant liens in their assets (subject to certain excluded assets) to secure the obligations under the Notes. There are currently no liens associated with the Notes.

The Purchase Agreement also requires compliance with two financial covenants. MEP must not permit the ratio of consolidated funded debt to pro forma EBITDA (the total leverage ratio), as of the end of any applicable four quarter period, to exceed 5.00 to 1.00, or 5.50 to 1.00 during acquisition periods. MEP also must maintain, on a consolidated basis, as of the end of each applicable four-quarter period, a ratio of pro forma EBITDA to consolidated interest expense for such four quarter period then ended of at least 2.50 to 1.00.

At March 31, 2017, MEP was in compliance or deemed in compliance with the terms of its financial covenants under the Notes and the related purchase agreement. The total leverage ratio of MEP and its consolidated subsidiaries with respect to the four-quarter period ending March 31, 2017, was 5.42x. On May 9, 2017, MEP exercised its right to issue sufficient Class A common units to the General Partner to result in a revised total leverage ratio of 4.80x, and thus, pursuant to the terms of the Notes and the related purchase agreement, is deemed in compliance with the total leverage ratio for the quarter ending March 31, 2017. Due to the low commodity price environment and the potential implications on MEP's results of operations, it is possible that MEP may not be able to meet the total leverage ratio financial covenant at some point during 2017 without further action on its part. If this were to occur, MEP would seek a waiver from the note holders, seek additional capital contributions, pursue refinancing of the amounts outstanding under the Notes or seek to take other action to prevent a default under the Purchase Agreement and the Notes, although there is no assurance that MEP could obtain any such necessary preventative actions. Any failure to comply with one or both of the financial covenants could result in an event of default under the Purchase Agreement and the Notes and result in a cross-default under the MEP Credit Agreement. If an event of default were to occur, the note holders could, among other things, demand immediate payment of the Notes and trigger the springing liens. In addition, as discussed above, MEP and Midcoast Operating are restricted from making distributions to us in certain circumstances involving certain defaults under that agreement or any event of default under that agreement. Furthermore, a default under the MEP Credit Agreement or Purchase Agreement would limit our ability to receive payment of amounts that may be owed to us under the Financial Support Agreement. Any inability of MEP or Midcoast Operating to make distributions, or of Midcoast Operating to repay its indebtedness to us, could reduce our cash flows and affect our results of operations.

On April 27, 2017, we entered into a definitive agreement with our General Partner to sell our ownership interest in our natural gas business. As part of the of the agreement our General Partner will acquire our 48.4% interest in Midcoast Operating, our 51.9% interest in MEP and our 100% interest in MEP's General Partner. MEP's outstanding debt obligation under the MEP Senior Notes will not be repaid at the closing of the transaction, rather it will remain outstanding and continue as an ongoing obligation of MEP.

Capital Resources

Equity and Debt Securities

Execution of our growth strategy and completion of our planned construction projects contemplate our accessing the public and private equity and credit markets to obtain the capital necessary to fund these activities. We have issued a balanced combination of debt and equity securities to fund our expansion projects and acquisitions. Our internal growth projects and targeted acquisitions will require additional permanent capital and require us to bear the cost of constructing and acquiring assets before we begin to realize a return on them. From time to time, if the capital markets are constrained, our ability and willingness to complete future debt and equity offerings may be limited, which in turn, could affect our ability to execute our growth strategy or complete our planned construction projects. The timing of any future debt and equity offerings will depend on various factors, including prevailing market conditions, interest rates, our financial condition and our credit rating at the time.

Subject to the foregoing, from time to time, we may seek to satisfy liquidity needs through the issuance of registered debt or equity securities. We have a current shelf registration statement on Form S-3 that allows us to issue an unlimited amount of equity and debt securities in underwritten public offerings.

Joint Funding Arrangements

In order to obtain capital, we have explored, and may continue to explore, numerous options, including joint funding arrangements.

Joint Funding Arrangement for Bakken Pipeline System

On April 27, 2017, our Board of Directors finalized the joint funding arrangement with our General Partner for the Bakken Pipeline System. Under the terms of the arrangement, our General Partner owns 75% and we own 25% of the Bakken Pipeline System, with a five year option for us to increase our interest by 20% at net book value.

Joint Funding Arrangement for Line 3 Replacement Program

On January 26, 2017, our Board of Directors approved a joint funding arrangement with our General Partner for the U.S. L3R Program. Under the terms of the arrangement, our General Partner will fund 99% and we will fund 1% of the capital cost of the U.S. L3R Program, with an option for us to increase our interest up to 40% in the U.S. portion at book value at any time up to four years after the project goes into service. Our General Partner paid us approximately $450.0 million for its 99% interest in the project, including our share of the construction costs to date.

Our General Partner made equity contributions totaling $18.8 million to the OLP for the three months ended March 31, 2017, to fund its equity portion of the construction costs associated with the U.S. L3R Program.

Joint Funding Arrangement for Eastern Access Projects

The OLP has a series of partnership interests, which we refer to as the EA interests. The EA interests were created to finance the Eastern Access Projects to increase access to refineries in the U.S. Upper Midwest and in Ontario, Canada for light crude oil produced in western Canada and the United States. Until January 26, 2017, our General Partner owned 75% of the EA interests, and the projects were jointly funded by our General Partner at 75%

and us at 25%. On January 26, 2017, we exercised our option under the Eastern Access joint funding arrangement to acquire an additional 15% interest in the Eastern Access Projects, which is now in service, at its book value of approximately $360 million.

Our General Partner made equity contributions totaling $5.6 million and $7.2 million to the OLP for the three months ended March 31, 2017 and 2016, respectively, to fund its equity portion of the construction costs associated with the Eastern Access Projects.

Joint Funding Arrangement for the U.S. Mainline Expansion

The OLP also has a series of partnership interests, which we refer to as the ME interests. The ME interests were created to finance the Mainline Expansion Projects to increase access to the markets of North Dakota and western Canada for light oil production on our Lakehead System between Neche, North Dakota and Superior, Wisconsin. Our General Partner owns 75% of the ME interests, and the projects are jointly funded by our General Partner at 75% and us at 25%, under the Mainline Expansion joint funding arrangement , which is similar to the Eastern Access joint funding arrangement.

Our General Partner has made equity contributions totaling $14.5 million and $42.8 million to the OLP for the three months ended March 31, 2017 and 2016, respectively, to fund its equity portion of the construction costs associated with the Mainline Expansion Projects.

All other operations are captured by the Lakehead and Alberta Clipper interests, which are owned 100% by us. For further details regarding our joint funding arrangements refer to Item 1. *Financial Statements*, Note 17. *Related Party Transactions*.

Sale of Accounts Receivable

We and certain of our subsidiaries were parties to a receivables purchase arrangement, which we refer to as the Receivables Agreement, with an indirect, wholly-owned subsidiary of Enbridge. Pursuant to the Receivables Agreement, the Enbridge subsidiary purchased on a monthly basis, for cash, current accounts receivables and accrued receivables, or the receivables, of certain of our subsidiaries and certain subsidiaries of MEP that were participating sellers under the Receivables Agreement, up to an aggregate monthly maximum of $450.0 million, net of receivables that have not been collected. The Receivables Agreement was amended in June 2016 to extend the termination date of the agreement to December 31, 2019.

For the three months ended March 31, 2017, we sold and derecognized $965.8 million of receivables to an indirect, wholly-owned subsidiary of Enbridge, and we received cash proceeds of $965.2 million. As of March 31, 2017, outstanding receivables of $275.2 million, which had been sold and derecognized, had not been collected on behalf of the Enbridge subsidiary.

On April 27, 2017, we terminated our Receivables Agreement, with the indirect, wholly-owned subsidiary of Enbridge in exchange for a one-time $5 million payment to us.

For further details regarding the Receivables Agreement, refer to Item 1. *Financial Statements*, Note. 17. *Related Party Transactions*.

Cash Requirements

Capital Spending

We categorize our capital expenditures as either maintenance capital or expansion capital expenditures. Maintenance capital expenditures are those expenditures that are necessary to maintain the service capability of our existing assets and include the replacement of system components and equipment which are worn, obsolete or completing its useful lives. 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. Expenditure levels will increase as pipelines age and require higher levels of inspection, maintenance and capital replacement. We also anticipate that maintenance capital will increase due to the growth of our pipeline systems and the aging of portions of these systems. Maintenance capital expenditures are expected to be funded by operating cash flows.

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. We anticipate funding expansion capital expenditures temporarily through borrowing under the terms of our Credit Facility, with permanent debt and equity funding being obtained when appropriate.

We maintain a comprehensive integrity management program for our pipeline systems, which relies on the latest technologies that include internal pipeline inspection tools. These internal pipeline inspection tools identify internal and external corrosion, dents, cracking, stress corrosion cracking and combinations of these conditions. We regularly assess the integrity of our pipelines utilizing the latest generations of metal loss, caliper and crack detection internal pipeline inspection tools. We also conduct hydrostatic testing to determine the integrity of our pipeline systems. Accordingly, we incur substantial expenditures each year for our integrity management programs. We expect to incur continuing annual capital and operating expenditures for pipeline integrity measures to ensure both regulatory compliance and to maintain the overall integrity of our pipeline systems. Under our capitalization policy, expenditures that replace major components of property or extend the useful lives of existing assets are capital in nature, while expenditures to inspect and test our pipelines are usually considered operating expenses.

We incurred capital expenditures of approximately $97.6 million for the three months ended March 31, 2017, including $10.0 million of maintenance capital expenditures. Of those capital expenditures, $38.7 million were financed by contributions from our General Partner via joint funding arrangements. At March 31, 2017, we had approximately $337.9 million in outstanding purchase commitments attributable to capital projects for the construction of assets that will be recorded as property, plant and equipment in the future.

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 our Credit Facilities, joint funding arrangements 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.

As discussed above, on February 15, 2017, through our joint venture with MPC we acquired a minority stake in the Bakken Pipeline System. For further details regarding our funding arrangements refer to *Future Prospects Update for Liquids — Bakken Pipeline System.*

Forecasted Expenditures

We estimate our capital expenditures based upon our strategic operating and growth plans, which are also dependent upon our ability to produce or otherwise obtain the financing necessary to accomplish our growth objectives. The following table sets forth our estimated maintenance and expansion capital expenditures, net of joint funding, of $405 million for the year ending December 31, 2017 without giving effect to the sale of our natural gas business. We expect to receive funding of approximately $420 million from our General Partner based on our joint funding arrangements for the U.S. L3R Program, Eastern Access Projects and Mainline Expansion Projects. Although we anticipate making these expenditures in 2017, these estimates may change due to factors beyond our control, including weather-related issues, construction timing, regulatory permitting, 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.

	Total Forecasted Expenditures[1] (in millions)
Liquids Projects	
Eastern Access Projects	$ 30
U.S. Mainline Expansions	75
Line 3 Replacement	350
Liquids Integrity Program	100
Expansion Capital	160
Maintenance Capital Expenditures	75
	790
Less joint funding from:	
General Partner	420
Liquids Total	$370
Natural Gas Projects	
Expansion Capital	$ 40
Maintenance Capital Expenditure	35
	75
Less joint funding from:	
MEP	40
Natural Gas Total	$ 35
Total	$405

(1) Amounts do not include forecasted Allowance for Funds Used During Construction, or AFUDC.

Environmental

Lakehead Line 6B Crude Oil Release

During the three months ended March 31, 2017, our cash flows were affected by the approximate $2.0 million we paid for the environmental remediation, restoration and cleanup activities resulting from the crude oil release that occurred in 2010 on Line 6B of our Lakehead system.

In March 2013, we and Enbridge filed a lawsuit against the insurers of $145.0 million of coverage, as one particular insurer is disputing our recovery eligibility for costs related to our claim on the Line 6B crude oil release and the other remaining insurers asserted that their payment was predicated on the outcome of our recovery with that insurer. We received a partial recovery payment of $42.0 million from the other remaining insurers and amended our lawsuit such that it includes only one insurer. Of the remaining $103.0 million coverage limit, $85.0 million is the subject matter of a lawsuit Enbridge filed against one particular insurer described above. In March 2015, Enbridge reached agreement with that insurer to submit the $85.0 million claim to binding arbitration. The recovery of the remaining $18.0 million is awaiting resolution of that arbitration, which began in the fourth quarter of 2016. While we believe that those costs are eligible for recovery, there can be no assurance that we will prevail. For more information regarding cost estimates and fines and penalties, refer to Item 1. *Financial Statements*, Note 18. *Commitments and Contingencies*.

Derivative Activities

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, 2017 for each of the indicated calendar years:

	Notional[1]	2017	2018	2019	2020	2021 & Thereafter	Total[2]
				(in millions)			
Swaps:							
Natural gas	35,035,000	$ 1.4	$ —	$—	$—	$—	$ 1.4
NGL	7,894,750	(7.8)	—	—	—	—	(7.8)
Crude Oil	1,545,950	—	—	—	—	—	—
Options:							
NGL – puts purchased	1,237,500	2.8	—	—	—	—	2.8
NGL – calls written	1,237,500	(7.1)	—	—	—	—	(7.1)
Crude Oil – puts purchased	572,500	4.9	0.2	—	—	—	5.1
Crude Oil – calls written	572,500	(0.4)	(0.5)	—	—	—	(0.9)
Forward contracts:							
Natural gas	54,106,730	0.4	0.1	—	—	—	0.5
NGL	23,530,098	6.6	(0.9)	—	—	—	5.7
Crude Oil	254,824	(0.7)	—	—	—	—	(0.7)
Totals		$ 0.1	$(1.1)	$—	$—	$—	$(1.0)

(1) Notional amounts for natural gas are recorded in MMBtu, whereas NGLs and crude oil are recorded in Bbl.

(2) Fair values exclude credit valuation adjustment gains of approximately $0.1 million at March 31, 2017.

The following table provides summarized information about the timing and estimated settlement amounts of our outstanding interest rate derivatives calculated based on implied forward rates in the yield curve at March 31, 2017 for each of the indicated calendar years:

	Notional	2017	2018	2019	2020	2021	Total[1]
				(in millions)			
Interest Rate Derivatives							
Interest Rate Swaps:							
Floating to Fixed	1,430	$ (5.3)	$ (6.7)	$(1.5)	$—	$—	$ (13.5)
Pre-issuance hedges	1,350	(137.7)	(13.3)	—	—	—	(151.0)
		$(143.0)	$(20.0)	$(1.5)	$—	$—	$(164.5)

(1) Fair values exclude credit valuation adjustment gains of approximately $0.8 million at March 31, 2017.

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 months ended March 31, 2017	For the three months ended March 31, 2016	Variance 2017 vs. 2016 Increase (Decrease)
	(in millions)		
Total cash provided by (used in):			
Operating activities	$ 233.7	$ 266.3	$ (32.6)
Investing activities	(1,429.6)	(374.4)	(1,055.2)
Financing activities	1,191.4	98.6	1,092.8
Net decrease in cash and cash equivalents	(4.5)	(9.5)	5.0
Cash and cash equivalents at beginning of year	108.8	148.1	(39.3)
Cash and cash equivalents at end of period	$ 104.3	$ 138.6	$ (34.3)

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

	For the three months ended March 31, 2017	For the three months ended March 31, 2016	Variance 2017 vs. 2016
	(in millions)		
Receivables, trade and other	$ (8.0)	$ 9.8	$ (17.8)
Due from General Partner and affiliates	(11.7)	(32.6)	20.9
Accrued receivables	(20.8)	35.6	(56.4)
Inventory	(9.1)	19.8	(28.9)
Current and long-term other assets	22.7	5.8	16.9
Due to General Partner and affiliates	(76.0)	(30.3)	(45.7)
Accounts payable and other	27.9	(81.4)	109.3
Environmental liabilities	(6.5)	(5.0)	(1.5)
Accrued purchases	2.8	(32.1)	34.9
Interest payable	18.0	23.6	(5.6)
Property and other taxes payable	(2.0)	(3.2)	1.2
Changes in operating assets and liabilities	$(62.7)	$(90.0)	$ 27.3

Operating Activities

Net cash provided by our operating activities decreased $32.6 million for the three months ended March 31, 2017, compared to the same period in 2016, primarily due to decreased cash from net income after non-cash adjustments, partially offset by lower cash outflows from net changes in operating assets and liabilities. Decreased cash from net income after non-cash adjustments totaled $60.9 million and was primarily due to decreased rates on our liquids systems as well as decreased volumes on our natural gas systems, as described in *Results of Operations — by Segment*.

Cash outflows from net changes in operating assets and liabilities decreased $27.3 million. Our operating assets and liabilities fluctuate in the normal course of business due to various factors, including fluctuations in commodity prices and activity levels within our Natural Gas segment as well as timing of cash payments and receipts.

Investing Activities

Net cash used in our investing activities during the three months ended March 31, 2017 increased by $1,055.2 million compared to the same period in 2016 primarily due to increased cash outflows of $1,511.4 million from the acquisition of the Bakken Pipeline System. The increase in net cash used in investing activities was partially offset by a decrease in spending on capital projects of $245.2 million as most of these have now been placed into service, as well as cash inflows from the sale of the Ozark Pipeline System of $216.4 million.

Financing Activities

Net cash provided by our financing activities increased $1,092.8 million for the three months ended March 31, 2017 compared to the same period in 2016 primarily due to the following:

- Increased cash borrowings through a bridge loan of $1,500.0 million from EUS to a acquire minority investment in the Bakken Pipeline System; and
- Cash received from sale of 99% interest in U.S. L3R Project to our General Partner in the amount of $450.1 million.

These increases in net cash provided by our financing activities were partially offset by the following:

- Net repayments to short-term financing sources of $369.7 million;
- Cash used in the acquisition of additional 15% interest in the Eastern Access Projects of $360.3 million; and
- Increased cash distributions to noncontrolling interest of $111.5 million due to suspension of cash distributions to our General Partner on the Series EA and ME during the three months ended March 31, 2016. Distributions resumed during the three months ended March 31, 2017.

REGULATORY MATTERS

FERC Transportation Tariffs

Under current policy, the FERC permits interstate pipelines that are subject to cost of service regulation to include an income tax allowance when calculating their regulated rates. On July 1, 2016, the U.S. Court of Appeals for the District of Columbia Circuit issued a decision that questions whether the combination of the FERC policy permitting regulated companies organized as pass-through entities for income tax purposes to include an allowance for income taxes in their rates, and the return on equity policy provides for a double recovery of income taxes. The court has remanded the case to the FERC to provide sufficient justification for its conclusion that there is no double recovery of income taxes for partnership owned pipelines receiving an income tax allowance in addition to the discounted cash flow return on equity. At this time, there is not enough information available to us to determine whether the level of income tax allowance or rate of return included in our regulated rates will change, and if so, by how much. However, if either the income tax allowance or rate of return policies are amended, our financial results could be impacted.

Lakehead System

Effective April 1, 2017, FERC tariff No. 43.22.0 adjusted rates to update the FSM. The FSM allows recovery of costs associated with particular shipper-approved projects through an incremental surcharge that is layered on top of the base index rates. The FSM surcharge reflects our projected costs for these shipper-approved projects for 2017 and an adjustment for the difference between estimated and actual costs and throughput for the prior year. The surcharge is applicable to all volumes entering our system from the effective date of the tariff, which we recognize as revenue when the barrels are delivered, typically a period of approximately 30 days from the date shipped.

This tariff filing decreased our transportation rate for heavy crude oil movements from the Canadian border to the Chicago, Illinois area by approximately $0.15 per barrel, to approximately $2.43 per barrel. The tariff filing also decreased our transportation rate for light crude oil movements from the Canadian border to the Chicago, Illinois area by approximately $0.13 per barrel, to approximately $2.01 per barrel. These decreases were primarily the result of an adjustment for the difference between estimated and actual costs and throughput for 2016, and a decrease in forecasted capital additions for 2017.

The Lakehead system is subject to one protest in 2017 in relation to FERC tariff 43.22.0. Suncor Energy Marketing Inc., or Suncor, filed a protest on March 15, 2017, claiming that EEP had improperly used cost of debt rates that result in an over-statement of approximately $43 million in its FSM revenue requirement, and therefore that the rates were unjust and unreasonable. We filed a response on March 20, 2017, stating that its cost of debt calculation was fully consistent with the Facilities Surcharge Settlement and Commission precedent. On March 30, 2017, the FERC issued an order accepting the tariff, suspending it for a nominal period, and allowing it to become effective April 1, 2017, subject to refund. The order also established that the issues raised are more appropriately addressed in hearing and settlement judge procedures.

North Dakota System

Effective January 1, 2017, FERC tariff No. 3.22.0 decreased rates to reflect the expiration of the Phase 5 Looping and Phase 6 Mainline surcharges. These surcharges were cost-of-service based surcharges that were adjusted each year to actual costs and volumes and were not subject to the FERC indexing methodology. This filing decreased our average transportation rates for all crude oil movements on our North Dakota system with a destination of Clearbrook, Minnesota by an average of approximately $0.43, to an average rate of approximately $1.33 per barrel.

Effective April 1, 2017, FERC tariff No. 3.23.0 established an initial interconnection charge at Stanley, North Dakota to facilitate a new pipeline interconnection with a third party. The newly established interconnection rate of $0.11 per BBL will only be charged to shippers utilizing this service.

SUBSEQUENT EVENTS

Sale of Natural Gas Business

On April 27, 2017, we entered into a definitive agreement with the General Partner to sell all of our ownership interests in our natural gas business. Under the agreement, we will sell our 48.4% limited partnership interest in Midcoast Operating, our 51.9% limited partnership interest in MEP, and our 100% interest in MEP's general partner for $2.15 billion, which amount includes cash proceeds of $1.31 billion and $840 million of outstanding indebtedness at MEP.

Redemption of Series 1 Preferred Units

On April 27, 2017, we redeemed all of our outstanding Series 1 Preferred Units held by our General Partner at face value of $1.2 billion. We funded the Series 1 Preferred Unit redemption through proceeds from the issuance of 64,308,682 Class A common units to our General Partner at a price of $18.66 per Class A common unit.

In addition, we will repay approximately $357 million in deferred distributions on the Series 1 Preferred Units owed to our General Partner with proceeds from the sale of our natural gas business.

Simplification of Incentive Distributions

On April 27, 2017, a wholly-owned subsidiary of our General Partner irrevocably waived all of its rights associated with its 66.1 million Class D units and 1,000 IDUs, in exchange for the issuance of 1,000 Class F units. For further information refer to Note 3. *Net Income per Limited Partner Unit*.

Joint Funding Arrangement for Bakken Pipeline System

On April 27, 2017, our Board of Directors finalized the joint funding arrangement with our General Partner for the Bakken Pipeline System. Under the terms of the arrangement, our General Partner owns 75% and we own 25% of the Bakken Pipeline System, with a five year option for us to increase our interest by 20% at net book value. With the finalization of the joint funding arrangement, we repaid the outstanding balance of $1.5 billion under the EUS Credit Agreement.

Distribution to Partners

On April 27, 2017, the board of directors of Enbridge Management declared a distribution payable to our partners on May 15, 2017. The distribution will be paid to unitholders of record as of May 8, 2017 of our available cash of $159.6 million at March 31, 2017, or $0.35 per limited partner unit. Of this distribution, $129.6 million will be paid in cash, $29.4 million will be distributed in i-units to our i-unitholder, Enbridge Management, and due to the i-unit distribution, $0.6 million will be retained from our General Partner from amounts otherwise distributable to it in respect of its general partner interest and limited partner interest to maintain its 2% general partner interest. Distributions to be paid include (i) distributions to the additional 64,308,682 Class A common units issued to the General Partner on April 27, 2017 and (ii) incentive distributions to the 1,000 Class F units. No distributions were made to the Class D units or the IDUs.

Distribution to Series EA Interests

On April 27, 2017, the board of directors of Enbridge Management, acting on behalf of Enbridge Pipelines (Lakehead) L.L.C., the managing general partner of the OLP and a holder of the Series EA interests, declared a distribution payable to the holders of the Series EA general and limited partner interests. The OLP will pay $62.0 million to the noncontrolling interest in the Series EA, while $29.3 million will be paid to us.

Distribution to Series ME Interests

On April 27, 2017, the board of directors of Enbridge Management, acting on behalf of Enbridge Pipelines (Lakehead) L.L.C., the managing general partner of the OLP and a holder of the Series ME interests, declared a distribution payable to the holders of the Series ME general and limited partner interests. The OLP will pay $38.0 million to the noncontrolling interest in the Series ME, while $12.7 million will be paid to us.

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 Form 10-K for the fiscal year ended December 31, 2016, filed on February 17, 2016, 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 changes in interest rates on our variable rate debt obligations. Our interest rate risk exposure does not exist within any of our segments, but exists at the corporate level where our fixed and variable rate debt obligations are issued. 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 interest rates, 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.

Interest Rate Derivatives

The table below provides information about our derivative financial instruments that we use to hedge the interest payments on our variable rate debt obligations that are sensitive to changes in interest rates and to lock in the interest rate on anticipated issuances of debt in the future. For interest rate swaps, the table presents notional amounts, the rates charged on the underlying notional amounts and weighted average interest rates paid by expected maturity dates. Notional amounts are used to calculate the contractual payments to be exchanged under the contract. Weighted average variable rates are based on implied forward rates in the yield curve at December 31, 2016.

				Fair Value[2] at	
Date of Maturity & Contract Type	**Accounting Treatment**	**Notional**	**Average Fixed Rate[1]**	**March 31, 2017**	**December 31, 2016**
			(dollars in millions)		
Contracts maturing in 2018					
Interest Rate Swaps – Pay Fixed	Cash Flow Hedge	$ 810	2.24%	$ (6.3)	$ (9.4)
Contracts maturing in 2019					
Interest Rate Swaps – Pay Fixed	Cash Flow Hedge	$ 620	2.96%	$ (7.2)	$ (7.3)
Contracts settling prior to maturity					
2017 – Pre-issuance Hedges	Cash Flow Hedge	$1,000	4.07%	$(137.7)	$(136.2)
2018 – Pre-issuance Hedges	Cash Flow Hedge	$ 350	3.08%	$ (13.3)	$ (13.1)

(1) Interest rate derivative contracts are based on the one-month or three-month London Interbank Offered Rate, or LIBOR.

(2) The fair value is determined from quoted market prices at March 31, 2017 and December 31, 2016, 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 adjustment gains of approximately $0.8 million and $1.2 million at March 31, 2017 and December 31, 2016, respectively.

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, 2017 and December 31, 2016.

	At March 31, 2017						At December 31, 2016	
			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 2017								
Swaps								
Receive variable/pay fixed	Natural Gas	3,820,000	$ 3.14	$ 3.00	$0.6	$(0.1)	$ 2.6	$ —
	NGL	3,504,500	$27.56	$28.16	$1.4	$(3.4)	$21.4	$ —
	Crude Oil	592,250	$51.51	$61.33	$0.4	$(6.2)	$ 0.9	$ (5.6)
Receive fixed/pay variable	NGL	4,390,250	$26.85	$28.18	$2.3	$(8.1)	$ —	$(27.5)
	Crude Oil	953,700	$57.71	$51.66	$6.8	$(1.0)	$ 5.7	$ (3.8)
Receive variable/pay variable	Natural Gas	21,085,000	$ 3.10	$ 3.05	$1.5	$(0.6)	$ 2.5	$ (0.4)
Physical Contracts								
Receive variable/pay fixed	Natural Gas	121,500	$ 2.68	$ 2.67	$ —	$ —	$ —	$ —
	NGL	1,084,520	$14.53	$10.50	$6.3	$ —	$ 0.9	$ —
Receive fixed/pay variable	Natural Gas	114,000	$ 2.71	$ 2.70	$ —	$ —	$ —	$ —
	NGL	1,514,234	$18.14	$19.25	$0.3	$(3.7)	$ —	$ (1.2)
Receive variable/pay variable	Natural Gas	48,471,230	$ 3.06	$ 3.06	$0.4	$ —	$ 0.6	$ —
	NGL	11,067,927	$23.46	$23.12	$4.5	$(0.8)	$ 2.6	$ (0.6)
	Crude Oil	254,824	$46.57	$49.12	$0.3	$(1.0)	$ 0.7	$ (2.0)
Portion of contracts maturing in 2018								
Swaps								
Receive variable/pay variable	Natural Gas	10,130,000	$ 2.97	$ 2.96	$0.3	$(0.3)	$ —	$ —
Physical Contracts								
Receive fixed/pay variable	NGL	110,238	$29.28	$30.27	$ —	$(2.7)	$ —	$ —
Receive variable/pay variable	Natural Gas	5,400,000	$ 3.33	$ 3.32	$0.1	$ —	$ 0.1	$ —
	NGL	9,753,179	$21.82	$21.63	$1.9	$(0.1)	$ 1.4	$ —

(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, 2017 and December 31, 2016, respectively, discounted using the swap rate for the respective periods to consider the time value of money. Fair values exclude credit valuation adjustment gains of approximately $0.1 million at March 31, 2017 and no gains at December 31, 2016, as well as cash collateral received.

The following table provides summarized information about the fair values of expected cash flows of our outstanding commodity options at March 31, 2017 and December 31, 2016.

	At March 31, 2017						At December 31, 2016	
					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 2017								
Puts (purchased)	NGL	1,237,500	$25.90	$32.13	$2.8	$ —	$3.4	$ —
	Crude Oil	481,250	$59.86	$51.69	$4.9	$ —	$4.6	$ —
Calls (written)	NGL	1,237,500	$30.06	$32.13	$ —	$(7.1)	$ —	$(13.4)
	Crude Oil	481,250	$68.19	$51.69	$ —	$(0.4)	$ —	$ (1.1)
Portion of option contracts maturing in 2018								
Puts (purchased)	Crude Oil	91,250	$42.00	$51.83	$0.2	$ —	$0.2	$ —
Calls (written)	Crude Oil	91,250	$51.75	$51.83	$ —	$(0.5)	$ —	$ (0.8)

(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, 2017 and December 31, 2016, respectively, discounted using the swap rate for the respective periods to consider the time value of money. Fair values exclude credit valuation adjustment gains with no gains at March 31, 2017 and approximately $0.1 million at December 31, 2016, 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.

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

	March 31, 2017	December 31, 2016
	(in millions)	
Counterparty Credit Quality[1]		
AA	$ (74.0)	$ (76.7)
A	(58.6)	(68.2)
Lower than A	(32.0)	(28.8)
	$(164.6)	$(173.7)

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

Item 4. Controls and Procedures

We 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, 2017. 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 months ended March 31, 2017.

PART II — OTHER INFORMATION

Item 1. Legal Proceedings

Refer to Part I, Item 1. *Financial Statements*, Note 18. *Commitments and Contingencies*, which is incorporated herein by reference.

Item 1A. Risk Factors

There have been no material changes to our risk factors previously disclosed in our Annual Report on Form 10-K for the fiscal year ended December 31, 2016, filed with the SEC on February 17, 2017.

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.

Enbridge Energy Partners, L.P.
(Registrant)

By: Enbridge Energy Management, L.L.C.
as delegate of
Enbridge Energy Company, Inc.
as General Partner

Date: May 10, 2017

By: /s/ Mark A. Maki
Mark A. Maki
President
(Principal Executive Officer)

Date: May 10, 2017

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
2.1	Agreement and Plan of Merger by and among Enbridge Energy Company, Inc., Enbridge Holdings (Leather) L.L.C., Midcoast Energy Partners, L.P. and Midcoast Holdings, L.L.C. dated as of January 26, 2017 (incorporated by reference to Exhibit 2.1 to the Current Report on Form 8-K, filed by Midcoast Energy Partners, L.P. on January 27, 2017).
3.1	Amendment No. 2 to the Seventh Amended and Restated Agreement of Limited Partnership of Enbridge Energy Partners, L.P., dated April 27, 2017 (incorporated by reference to Exhibit 3.1 to our Current Report on Form 8-K filed on May 3, 2017).
3.2	Eighth Amended and Restated Agreement of Limited Partnership of Enbridge Energy Partners, L.P., dated as of April 27, 2017 (incorporated by reference to Exhibit 3.2 to our Current Report on Form 8-K, filed on May 3, 2017).
10.1	Eighth Amended and Restated Agreement of Limited Partnership of Enbridge Energy, Limited Partnership, dated as of January 27, 2017 (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K, filed on January 27, 2017).
10.2	Support Agreement, dated January 26, 2017, by and among Enbridge Energy Partners, L.P., Enbridge Energy Company, Inc. and Midcoast Energy Partners, L.P., (incorporated by reference to Exhibit 10.2 to the Current Report on Form 8-K filed on January 27, 2017 by Midcoast Energy Partners, L.P.).
10.3	Credit Agreement dated as of February 15, 2017, by and among Enbridge Energy Partners, L.P. and Enbridge (U.S.) Inc. (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K, filed on February 15, 2017).
10.4	Purchase and Sale Agreement, dated as of April 27, 2017, by and between Enbridge Energy Partners, L.P. and Enbridge Energy Company, Inc. (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K, filed on May 3, 2017).
10.5	Contribution and Redemption Agreement, dated as of April 27, 2017, by and between Enbridge Energy Company, Inc. and Enbridge Energy Partners, L.P. (incorporated by reference to Exhibit 10.2 to our Current Report on Form 8-K filed on May 3, 2017).
10.6	Contribution Agreement, dated as of April 27, 2017, by and among Enbridge Energy Company, Inc., Enbridge Energy Partners, L.P. and Enbridge Holdings (DakTex) L.L.C. (incorporated by reference to Exhibit 10.3 to our Current Report on Form 8-K filed on May 3, 2017).
10.7	Amended and Restated Limited Liability Company Agreement of Enbridge Holdings (DakTex) L.L.C., dated April 27, 2017, between Enbridge Energy Partners, L.P. and Enbridge Energy Company, Inc. (incorporated by reference to Exhibit 10.4 to our Current Report on Form 8-K filed on May 3, 2017).
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, Mark A. Maki, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of Enbridge 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 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 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 10, 2017

By: /s/ Mark A. Maki

Mark A. Maki
President
(Principal Executive Officer)
Enbridge Energy Management, L.L.C.
(as delegate of 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 Enbridge 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 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 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 10, 2017

By: /s/ Stephen J. Neyland

Stephen J. Neyland
Vice President — Finance
(Principal Financial Officer)
Enbridge Energy Management, L.L.C.
(as delegate of 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 Enbridge Energy Partners, L.P. (the ''Partnership''), hereby certifies that the Partnership's Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2017 (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 the Partnership.

Date: May 10, 2017

By: /s/ Mark A. Maki

Mark A. Maki
President
(Principal Executive Officer)
Enbridge Energy Management, L.L.C.
(as delegate of 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 Enbridge Energy Partners, L.P. (the ''Partnership''), hereby certifies that the Partnership's Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2017 (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 the Partnership.

Date: May 10, 2017

By: /s/ Stephen J. Neyland

Stephen J. Neyland
Vice President — Finance
(Principal Financial Officer)
Enbridge Energy Management, L.L.C.
(as delegate of the General Partner)