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

FORM 10-Q

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

For the quarterly period ended June 30, 2016

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, or a smaller reporting company. See the definitions of ''large accelerated filer,'' ''accelerated filer'' and ''smaller reporting company'' in Rule 12b-2 of the Exchange Act. (Check one):

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

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ☐ No ☒

The registrant had 262,208,428 Class A common units outstanding as of July 28, 2016.

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) 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; (2) our ability to successfully complete and finance expansion projects; (3) the effects of competition, in particular, by other pipeline systems; (4) shut-downs or cutbacks at our facilities or refineries, petrochemical plants, utilities or other businesses for which we transport products or to which we sell products; (5) hazards and operating risks that may not be covered fully by insurance, including those related to Line 6B and any additional fines and penalties assessed in connection with the crude oil release on that line; (6) 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; (7) changes in or challenges to our tariff rates; (8) 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 (9) permitting at federal, state and local levels in regards to the construction of new assets.

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, 2015, which is available to the public over the Internet at the United States 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 June 30,		For the six months ended June 30,	
	2016	2015	2016	2015
	(unaudited; in millions, except per unit amounts)			
Operating revenues:				
Commodity sales (Note 12)	$ 379.4	$ 702.7	$ 757.2	$1,503.6
Commodity sales – affiliate (Notes 10 and 12)	1.4	28.4	6.6	50.2
Transportation and other services (Note 12)	638.2	548.5	1,294.2	1,123.2
Transportation and other services – affiliate (Note 10)	29.9	33.5	52.5	64.7
	1,048.9	1,313.1	2,110.5	2,741.7
Operating expenses:				
Commodity costs (Notes 5 and 12)	350.5	647.5	685.9	1,408.7
Commodity costs – affiliate (Note 10)	8.6	23.1	21.2	41.0
Environmental costs, net of recoveries (Note 11)	0.1	(0.8)	17.0	—
Operating and administrative	102.7	91.5	198.8	189.7
Operating and administrative – affiliate (Note 10)	110.1	115.7	228.6	234.6
Power	59.7	57.2	132.5	120.8
Depreciation and amortization	144.9	129.5	285.8	257.9
Goodwill impairment	—	246.7	—	246.7
Asset impairment (Note 6)	10.6	12.3	11.0	12.3
	787.2	1,322.7	1,580.8	2,511.7
Operating income (loss)	261.7	(9.6)	529.7	230.0
Interest expense, net (Notes 8 and 12)	(101.5)	(78.0)	(214.4)	(126.3)
Allowance for equity used during construction (Note 16)	13.3	17.3	25.6	40.3
Other income (Note 10)	6.7	6.0	14.2	11.9
Income (loss) before income tax (expense) benefit	180.2	(64.3)	355.1	155.9
Income tax (expense) benefit (Note 13)	(2.5)	3.8	(5.0)	1.4
Net income (loss)	177.7	(60.5)	350.1	157.3
Less: Net income attributable to:				
Noncontrolling interest (Note 9)	70.3	10.0	139.1	61.3
Series 1 preferred unit distributions	22.5	22.5	45.0	45.0
Accretion of discount on Series 1 preferred units	1.2	4.1	2.3	8.0
Net income (loss) attributable to general and limited partner ownership interests in Enbridge Energy Partners, L.P.	$ 83.7	$ (97.1)	$ 163.7	$ 43.0
Net income (loss) allocable to common units and i-units	$ 27.7	$ (149.4)	$ 51.8	$ (63.5)
Net income (loss) per common unit and i-unit (basic and diluted) (Note 2)	$ 0.08	$ (0.44)	$ 0.15	$ (0.18)
Weighted average common units and i-units outstanding (basic and diluted)	347.1	339.9	345.9	336.3

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 June 30,		For the six months ended June 30,	
	2016	2015	2016	2015
	(unaudited; in millions)			
Net income (loss)	$177.7	$(60.5)	$ 350.1	$157.3
Other comprehensive income (loss), net of tax expense (Note 12)	(41.7)	96.6	(119.3)	(50.2)
Comprehensive income	136.0	36.1	230.8	107.1
Less:				
Net income attributable to noncontrolling interest (Note 9)	70.3	10.0	139.1	61.3
Net income attributable to Series 1 preferred unit distributions	22.5	22.5	45.0	45.0
Net income attributable to accretion of discount on Series 1 preferred units	1.2	4.1	2.3	8.0
Other comprehensive loss allocated to noncontrolling interest	—	(1.9)	—	(2.6)
Comprehensive income (loss) attributable to general and limited partner ownership interests in Enbridge Energy Partners, L.P.	$ 42.0	$ 1.4	$ 44.4	$ (4.6)

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

ENBRIDGE ENERGY PARTNERS, L.P.

CONSOLIDATED STATEMENTS OF CASH FLOWS

	For the six months ended June 30,	
	2016	2015
	(unaudited; in millions)	
Cash provided by operating activities:		
Net income	$ 350.1	$ 157.3
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	285.8	257.9
Derivative fair value net losses (Note 12)	83.1	39.5
Inventory market price adjustments (Note 5)	—	5.3
Goodwill impairment	—	246.7
Environmental costs, net of recoveries (Note 11)	15.7	(1.0)
Distributions from investments in joint ventures	13.7	11.6
Equity earnings from investments in joint ventures	(13.7)	(11.6)
Allowance for equity used during construction	(25.6)	(40.3)
Amortization of debt issuance and hedging costs	20.8	6.1
Asset impairment	11.0	12.3
Other	0.2	(4.0)
Changes in operating assets and liabilities, net of acquisitions:		
Receivables, trade and other	19.6	45.7
Due from General Partner and affiliates	(47.1)	(62.7)
Accrued receivables	24.7	158.9
Inventory	(14.4)	(1.3)
Current and long-term other assets	(22.6)	(33.0)
Due to General Partner and affiliates	(27.5)	66.9
Accounts payable and other	(93.6)	(56.6)
Environmental liabilities	(10.0)	(21.6)
Accrued purchases	(7.7)	(114.8)
Interest payable	(1.3)	1.2
Property and other taxes payable	(14.7)	(15.6)
Net cash provided by operating activities	546.5	646.9
Cash used in investing activities:		
Additions to property, plant and equipment (Note 15)	(678.1)	(994.9)
Asset acquisitions	—	(85.0)
Changes in restricted cash	11.9	78.6
Investments in joint ventures	—	(2.5)
Distributions from investments in joint ventures in excess of cumulative earnings	7.3	6.7
Other	(1.2)	0.8
Net cash used in investing activities	(660.1)	(996.3)
Cash provided by financing activities:		
Net proceeds from unit issuances	—	294.8
Distributions to partners (Note 9)	(432.0)	(403.8)
Repayments to General Partner	—	(306.0)
Net borrowings (repayments) under credit facilities (Note 8)	615.0	(300.0)
Net commercial paper borrowings (repayments) (Note 8)	(131.8)	644.9
Contributions from noncontrolling interest (Note 10)	63.4	502.6
Distributions to noncontrolling interest (Note 10)	(15.2)	(171.2)
Other	(0.8)	—
Net cash provided by financing activities	98.6	261.3
Net decrease in cash and cash equivalents	(15.0)	(88.1)
Cash and cash equivalents at beginning of year	148.1	197.9
Cash and cash equivalents at end of period	$ 133.1	$ 109.8

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

ENBRIDGE ENERGY PARTNERS, L.P.

CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

	June 30, 2016	December 31, 2015
	(unaudited; in millions)	
ASSETS		
Current assets:		
Cash and cash equivalents (Note 4)	$ 133.1	$ 148.1
Restricted cash (Note 4)	22.7	37.6
Receivables, trade and other, net of allowance for doubtful accounts of $2.6 million and $2.5 million at June 30, 2016 and December 31, 2015, respectively	5.7	25.2
Due from General Partner and affiliates (Note 10)	106.5	59.4
Accrued receivables	53.2	77.9
Inventory (Note 5)	49.5	35.1
Other current assets (Notes 6, 12 and 16)	146.1	173.0
	516.8	556.3
Property, plant and equipment, net (Notes 6 and 16)	17,643.0	17,412.4
Intangible assets, net	268.2	280.0
Other assets, net (Notes 8, 10 and 12)	485.5	525.6
	$18,913.5	$18,774.3
LIABILITIES AND PARTNERS' CAPITAL		
Current liabilities:		
Due to General Partner and affiliates (Note 10)	$ 163.4	$ 190.9
Accounts payable and other (Notes 4, 12 and 16)	431.8	654.9
Environmental liabilities (Note 11)	110.3	95.8
Accrued purchases	138.4	146.1
Interest payable	97.6	98.9
Property and other taxes payable (Note 13)	89.0	103.7
Current maturities of long-term debt (Note 8)	299.9	300.0
	1,330.4	1,590.3
Long-term debt (Note 8)	8,213.9	7,728.4
Due to General Partner and affiliates (Note 10)	283.2	238.3
Other long-term liabilities (Notes 11, 12 and 13)	371.9	305.2
	10,199.4	9,862.2
Commitments and contingencies (Note 11)		
Partners' capital: (Note 9)		
Series 1 preferred units (48,000,000 authorized and issued at June 30, 2016 and December 31, 2015)	1,189.1	1,186.8
Class D units (66,100,000 authorized and issued at June 30, 2016 and December 31, 2015)	2,517.6	2,517.6
Class E units (18,114,975 authorized and issued at June 30, 2016 and December 31, 2015)	778.2	778.2
Class A common units (262,208,428 authorized and issued at June 30, 2016 and December 31, 2015)	—	—
Class B common units (7,825,500 authorized and issued at June 30, 2016 and December 31, 2015)	—	—
i-units (78,004,678 and 73,285,739 authorized and issued at June 30, 2016 and December 31, 2015, respectively)	—	212.6
Incentive distribution units (1,000 authorized and issued at June 30, 2016 and December 31, 2015)	495.1	495.0
General Partner	91.6	147.4
Accumulated other comprehensive loss (Note 12)	(489.3)	(370.0)
Total Enbridge Energy Partners, L.P. partners' capital	4,582.3	4,967.6
Noncontrolling interest (Note 9)	4,131.8	3,944.5
Total partners' capital	8,714.1	8,912.1
	$18,913.5	$18,774.3

Variable Interest Entities (VIEs) — see Note 7.

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

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (unaudited)

1. BASIS OF PRESENTATION

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 June 30, 2016, our results of operations for the three and six months ended June 30, 2016 and 2015, and our cash flows for the six months ended June 30, 2016 and 2015. We derived our consolidated statement of financial position as of December 31, 2015 from the audited financial statements included in our Annual Report on Form 10-K for the fiscal year ended December 31, 2015. Our results of operations for the three and six months ended June 30, 2016 and 2015, 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, 2015.

2. 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 calculate 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.

2. 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 June 30,		For the six months ended June 30,	
	2016	2015	2016	2015
	(in millions, except per unit amounts)			
Net income (loss)	$ 177.7	$ (60.5)	$ 350.1	$ 157.3
Less: Net income attributable to:				
Noncontrolling interest	70.3	10.0	139.1	61.3
Series 1 preferred unit distributions	22.5	22.5	45.0	45.0
Accretion of discount on Series 1 preferred units	1.2	4.1	2.3	8.0
Net income (loss) attributable to general and limited partner interests in Enbridge Energy Partners, L.P.	83.7	(97.1)	163.7	43.0
Distributions:				
Incentive distributions	(5.2)	(5.1)	(10.4)	(8.5)
Distributed earnings attributed to our General Partner	(5.3)	(5.2)	(10.5)	(10.2)
Distributed earnings attributed to Class D and Class E units	(49.1)	(49.1)	(98.2)	(97.1)
Total distributed earnings to our General Partner, Class D and Class E units and IDUs	(59.6)	(59.4)	(119.1)	(115.8)
Total distributed earnings attributed to our common units and i-units	(202.9)	(198.5)	(404.6)	(392.0)
Total distributed earnings	(262.5)	(257.9)	(523.7)	(507.8)
Overdistributed earnings	$(178.8)	$(355.0)	$(360.0)	$(464.8)
Weighted average common units and i-units outstanding	347.1	339.9	345.9	336.3
Basic and diluted earnings per unit:				
Distributed earnings per common unit and i-unit[(1)]	$ 0.58	$ 0.58	$ 1.17	$ 1.17
Overdistributed earnings per common unit and i-unit[(2)]	(0.50)	(1.02)	(1.02)	(1.35)
Net income (loss) per common unit and i-unit (basic and diluted)[(3)]	$ 0.08	$ (0.44)	$ 0.15	$ (0.18)

(1) 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.

(2) 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.

(3) For the three and six months ended June 30, 2016 and 2015, 43,201,310 anti-dilutive Preferred units, 66,100,000 anti-dilutive Class D units and 18,114,975 anti-dilutive Class E units were excluded from the if-converted method of calculating diluted earnings per unit.

3. ACQUISITIONS

On February 27, 2015, Midcoast Energy Partners, L.P., or MEP, acquired a midstream business in Leon, Madison and Grimes Counties, Texas. The acquisition consisted of a natural gas gathering system. MEP acquired the midstream business for $85.0 million in cash and a contingent future payment of up to $17.0 million.

Of the $85.0 million purchase price, $20.0 million was placed into escrow, pending the resolution of a legal matter and completion of additional wells connecting to the system within one year of the acquisition date. During the second quarter of 2016, MEP released $6.0 million from escrow for the resolution of a legal matter. Since the acquisition date, MEP has also released $11.0 million from escrow for additional wells connected to the system. During the first quarter of 2016, $3.0 million in escrow was returned to MEP as some of the additional wells were not connected to the system within one year of the acquisition date. For the six months ended June 30, 2016, a $3.0 million gain was recognized as a reduction to ‘‘Operating and administrative’’ expense in our consolidated statement of income related to the return of these escrow funds. At June 30, 2016, no amounts remained in escrow.

3. ACQUISITIONS – (continued)

The purchase and sale agreement contained a provision whereby MEP would have been obligated to make future tiered payments of up to $17.0 million if volumes are delivered into the system at certain tiered volume levels over a five-year period. MEP determined at the time of the acquisition that the potential payment was contingent consideration. At the acquisition date, the fair value of this contingent consideration, using a probability-weighted discounted cash flow model was $2.3 million. The contingent consideration was re-measured on a fair value basis each quarter until December 31, 2015, which resulted in an addition to the liability of $0.3 million for accretion. During the first quarter of 2016, MEP determined, based on current and forecasted volumes, that it is remote that it will be obligated to make any payments at the expiration of the five-year period. Consequently, the liability was reversed and a $2.6 million gain was recognized as a reduction to ‘‘Operating and administrative’’ expense in our consolidated statement of income for the six months ended June 30, 2016.

4. 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 $7.4 million and $21.5 million at June 30, 2016, and December 31, 2015, respectively, are included in ‘‘Accounts payable and other’’ on our consolidated statements of financial position.

Restricted Cash

Restricted cash is comprised of the following:

	June 30, 2016	December 31, 2015
	(in millions)	
Cash collected on behalf of Enbridge subsidiary for accounts receivable sales and not yet remitted to the Enbridge subsidiary (see Note 10)	$22.7	$19.0
Cash held in escrow for acquisitions (see Note 3)	—	6.0
Cash collateral for derivative activities (see Note 12)	—	12.6
	$22.7	$37.6

5. INVENTORY

Our inventory is comprised of the following:

	June 30, 2016	December 31, 2015
	(in millions)	
Materials and supplies	$ 2.2	$ 2.2
Crude oil inventory	0.2	1.6
Natural gas and NGL inventory	47.1	31.3
	$49.5	$35.1

‘‘Commodity costs’’ on our consolidated statements of income include charges totaling $0.7 million and $5.3 million for the three and six months ended June 30, 2015, respectively, that we recorded to reduce the cost basis of our inventory of natural gas and NGLs, to reflect the current market value. For the three and six months ended June 30, 2016, we did not have any similar material charges related to our inventory of natural gas and NGLs.

6. PROPERTY, PLANT AND EQUIPMENT

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

	June 30, 2016	December 31, 2015
	(in millions)	
Land	$ 77.1	$ 62.9
Rights-of-way	954.9	952.5
Pipelines	10,464.2	10,376.3
Pumping equipment, buildings and tanks	4,589.8	4,232.3
Compressors, meters and other operating equipment	2,172.3	2,147.6
Vehicles, office furniture and equipment	238.1	280.0
Processing and treating plants	629.8	627.8
Construction in progress	1,962.6	1,968.8
Total property, plant and equipment	21,088.8	20,648.2
Accumulated depreciation	(3,445.8)	(3,235.8)
Property, plant and equipment, net	$17,643.0	$17,412.4

In May 2016, MEP implemented a plan to sell certain trucking assets in the Natural Gas segment with a total carrying amount of $24.6 million including $2.2 million of customer relationship intangible assets. As of May 31, 2016, these assets were reclassified as held for sale in ''Other current assets'' on our consolidated statements of financial position at fair value, net of estimated costs to sell. Recognition of depreciation expense ceased upon reclassification of these assets. An expected loss of $10.6 million was recorded on disposal from sale of these assets during the second quarter of 2016. These non-cash impairment charges are included in ''Asset impairment'' on our consolidated statements of income. The sale is expected to occur in the third quarter of 2016.

7. VARIABLE INTEREST ENTITIES

Principles of Consolidation

On January 1, 2016, we adopted Accounting Standards Update No. 2015-02, which amended consolidation guidance to, among other things, eliminate the specialized consolidation model and guidance for limited partnerships, including the presumption that the general partner should consolidate a limited partnership. As a result, we have determined that certain entities that we historically consolidated under this presumption are variable interest entities, or VIEs. Further, we determined that we are the primary beneficiary for these VIEs and will continue to consolidate these entities under the amended guidance. While the amended guidance did not impact our conclusion that such entities should be consolidated, because such entities are now considered VIEs, additional disclosures are necessary. We have applied this amended guidance retrospectively to our disclosures.

The consolidated financial statements include our accounts, and accounts of our subsidiaries and VIEs for which we are the primary beneficiary. Upon inception of a contractual agreement, we perform an assessment to determine whether the arrangement contains a variable interest in a legal entity and whether that legal entity is a VIE. Where we conclude we are the primary beneficiary of a VIE, we consolidate the accounts of that entity.

We assess all aspects of our interests in an entity and use judgment when determining if we are the primary beneficiary. The primary beneficiary has both the power to direct the activities of the VIE that most significantly impact the entity's economic performance and the obligation to absorb losses or the right to receive benefits from the VIE that could potentially be significant to the VIE. Other qualitative factors that are considered include decision-making responsibilities, the VIE capital structure, risk and rewards sharing, contractual agreements with the VIE, voting rights and level of involvement of other parties. Reassessment of the primary beneficiary conclusion is conducted on an ongoing basis as there are changes in the facts and circumstances related to each VIE.

All significant intercompany accounts and transactions are eliminated upon consolidation. Ownership interests in subsidiaries represented by other parties that do not control the entity are presented in the consolidated financial statements as activities and balances attributable to noncontrolling interests. Investments and entities over which we exercise significant influence are accounted for using the equity method.

7. VARIABLE INTEREST ENTITIES – (continued)

Midcoast Energy Partners, L.P.

MEP is a publicly-traded Delaware limited partnership. As of June 30, 2016, we owned a 51.9% direct limited partner interest in MEP. In addition, we own MEP's general partner, Midcoast Holdings GP, L.L.C. The public owns the remaining interests in MEP. We are the primary beneficiary of MEP because (1) through our ownership of MEP's general partner and our majority limited partner interest, we have the power to direct the activities that most significantly impact MEP's economic performance; and (2) we have the obligation to absorb losses and the right to receive residual returns that potentially could be significant to MEP.

As of June 30, 2016 and December 31, 2015, our consolidated statements of financial position include total assets of $5,045.4 million and $5,227.2 million, respectively, and total liabilities of $1,155.4 million and $1,220.7 million, respectively, related to MEP. Only the assets of MEP can be used to settle MEP's obligations. We currently do not have any obligation to provide financial support to MEP other than through certain contractual obligations, as prescribed by the terms of certain indemnities and guarantees, to pay specified liabilities of MEP.

Midcoast Operating, L.P.

Midcoast Operating is a Texas limited partnership. As of June 30, 2016, we and MEP owned 48.4% and 51.6%, respectively, of direct limited partner interest in Midcoast Operating. In addition, MEP owns Midcoast Operating's general partner, Midcoast OLP GP, L.L.C. MEP is the primary beneficiary of Midcoast Operating because (1) through MEP's ownership in Midcoast Operating's general partner and majority limited partner interest, MEP has the power to direct the activities that most significantly impact Midcoast Operating's economic performance; and (2) MEP has the obligation to absorb losses and the right to receive residual returns that potentially could be significant to Midcoast Operating. In addition, MEP is the entity within the related party group that is most closely associated with Midcoast Operating. As such, MEP consolidates Midcoast Operating. As discussed above, we consolidate MEP, and by extension also consolidate Midcoast Operating.

Enbridge Energy, Limited Partnership

Enbridge Energy, Limited Partnership, or OLP, is a Delaware limited partnership that has established several series of partnership interests. As of June 30, 2016, we owned, directly or indirectly, 100% of the general partner interests in each series of OLP, as well as 100% of the Series LH and Series AC limited partner interests in OLP. In addition, including our ownership of the general partner interests, we directly and indirectly owned 25% of the Series EA and Series ME interests in OLP. Our General Partner owns the remaining 75% interests in Series EA and Series ME interests in OLP. We are the primary beneficiary of OLP because (1) through our ownership of the general partner interests in each of the OLP's series and our limited partner interests in each series, we have the power to direct the activities that most significantly impact OLP's economic performance; and (2) we have the obligation to absorb losses and the right to receive residual returns that potentially could be significant to OLP. In addition, we are the entity within the related party group that is most closely associated with OLP.

As of June 30, 2016 and December 31, 2015, our consolidated statements of financial position include total assets of $11,333.4 million and $11,074.9 million, respectively, and total liabilities of $775.8 million and $998.2 million, respectively, related to OLP. Only the assets of OLP can be used to settle OLP's obligations. We currently do not have any obligation to provide financial support to OLP, although from time to time, we may provide certain indemnities and guarantees for payment of specified liabilities to third parties in the event that OLP becomes in default under contracts with those third parties.

North Dakota Pipeline Company, L.L.C.

North Dakota Pipeline Company, L.L.C., or NPDC, is a Delaware limited liability company. As of June 30, 2016, we directly owned 100% of the Class A units and 62.5% of the Class B units in NDPC. Williston Basin Pipeline LLC, or Williston, an affiliate of Marathon Petroleum Corporation, or MPC, owns the remaining 37.5% of Class B units in NDPC, which are used to fund the Sandpiper Project. We are the primary beneficiary of NDPC because (1) through our 100% ownership in NDPC's Class A units and majority ownership in its Class B units, we

7. VARIABLE INTEREST ENTITIES – (continued)

have the power to direct the activities that most significantly impact NDPC's economic performance; and (2) we have the obligation to absorb losses and the right to receive residual returns that potentially could be significant to NDPC.

As of June 30, 2016 and December 31, 2015, our consolidated statements of financial position include total assets of $1,797.0 million and $1,746.3 million, respectively, and total liabilities of $53.1 million and $84.8 million, respectively, related to NDPC. Only the assets of NDPC can be used to settle NDPC's obligations. We currently do not have any obligation to provide financial support to NDPC, although from time to time we may provide certain indemnities and guarantees for payment of specified liabilities to third parties in the event that NDPC becomes in default under contracts with those third parties.

The following table includes assets to be used to settle liabilities of our consolidated VIEs and liabilities of our consolidated VIEs for which creditors do not have recourse to our general credit as the primary beneficiary. These assets and liabilities are included in our consolidated balance sheet.

	June 30, 2016	December 31, 2015
	(in millions)	
ASSETS		
Cash and cash equivalents	$ 98.8	$ 108.7
Restricted cash	$ 16.8	$ 20.6
Receivables, trade and other, net	$ 3.9	$ 22.8
Due from General Partner and affiliates	$ 100.2	$ 51.9
Accrued receivables	$ 52.0	$ 77.4
Inventory	$ 49.4	$ 35.1
Other current assets	$ 141.7	$ 165.3
Property, plant and equipment, net	$16,963.0	$16,766.6
Intangible assets, net	$ 268.1	$ 279.8
Other assets, net	$ 481.9	$ 520.2
LIABILITIES		
Due to General Partner and affiliates	$ 110.0	$ 123.4
Accounts payable and other	$ 273.8	$ 534.2
Environmental liabilities	$ 110.1	$ 95.7
Accrued purchases	$ 137.5	$ 144.1
Interest payable	$ 8.5	$ 8.7
Property and other taxes payable	$ 85.3	$ 100.5
Long-term debt	$ 1,072.6	$ 1,087.4
Other long-term liabilities	$ 186.5	$ 209.7

8. 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 June 30, 2016, before the effect of our interest rate hedging activities. Our indebtedness with related parties is discussed in Note 10. *Related Party Transactions.*

	Interest Rate	June 30, 2016	December 31, 2015
		(in millions)	
EEP debt obligations:			
Commercial Paper[1]	1.403%	$ 194.3	$ 326.1
Credit Facilities due 2017 – 2020	2.645%	1,740.0	1,110.0
Senior Notes due December 2016	5.875%	300.0	300.0
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	3.929%	475.0	490.0
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		8,559.3	8,076.1
Other:			
Unamortized discount		(6.0)	(6.2)
Current maturities of long-term debt		(299.9)	(300.0)
Unamortized debt issuance costs		(39.5)	(41.5)
Total long term debt		$8,213.9	$7,728.4

(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.

On January 1, 2016, we adopted Accounting Standards Update No. 2015-03, which requires us to present debt issuance costs in the balance sheet as a reduction to the carrying amount of the debt liability, rather than as an asset. We have retrospectively adopted this guidance for all periods presented. The adoption of this guidance did not have a material impact on our consolidated financial statements.

8. DEBT – (continued)

Interest Cost

Our interest cost for the three and six months ended June 30, 2016, and 2015, is comprised of the following:

	For the three months ended June 30,		For the six months ended June 30,	
	2016	2015	2016	2015
	(in millions)			
Interest cost incurred[(1)]	$122.9	$84.1	$244.9	$144.6
Less: Interest capitalized	21.4	6.1	30.5	18.3
Interest expense	$101.5	$78.0	$214.4	$126.3

(1) Interest cost incurred increased period-over-period, due to an increase in our average outstanding debt balances outstanding and in part due to a decrease in unrealized losses for the six months ended June 30, 2015, that did not occur during the same period in 2016.

Credit Facilities and Commercial Paper

Our multi-year senior unsecured revolving credit facility, which we refer to as the Credit Facility, permits aggregate borrowings of up to, at any one time outstanding, $1.975 billion, a letter of credit subfacility and a swing line subfacility. The Credit Facility matures September 26, 2020; however, $175.0 million of commitments will expire on the original maturity date of September 26, 2018.

Our 364-day revolving credit agreement, which we refer to as the 364-Day Credit Facility, permits aggregate borrowings of up to $625.0 million: (1) on a revolving basis for a 364-day period, extendible annually at the lenders' discretion, and (2) for a 364-day term on a non-revolving basis following the expiration of all revolving periods. The current revolving credit termination date is June 30, 2017.

At June 30, 2016, the Credit Facility and 364-Day Credit Facility, together referred to as the Credit Facilities, provide an aggregate amount of approximately $2.6 billion of bank credit, which we use to fund our general activities and working capital needs. The amounts we may borrow under the terms of our Credit Facilities are reduced by the face amount of our letters of credit outstanding. During the six months ended June 30, 2016, we had net borrowings of $630.0 million, which includes gross borrowings of $7,255.0 million and gross repayments of $6,625.0 million.

We are party to an uncommitted letter of credit arrangement, pursuant to which the lender may, on a discretionary basis and with no commitment, agree to issue standby letters of credit upon our request. The aggregate amount of this uncommitted letter of credit is not to exceed $175.0 million. While the letter of credit arrangement is uncommitted and issuance of letters of credit is at the lender's sole discretion, we view this arrangement as a liquidity enhancement as it allows us to potentially reduce our reliance on utilizing our committed Credit Facilities for issuance of letters of credit to support our hedging activities.

Our commercial paper program provides for the issuance of up to an aggregate principal amount of $1.5 billion of commercial paper and is supported by our Credit Facilities. We access the commercial paper market primarily to provide temporary financing for our operating activities, capital expenditures and acquisitions when the available interest rates we can obtain are lower than the rates available under our Credit Facilities. During the six months ended June 30, 2016, we had net repayments of approximately $131.8 million, which includes gross borrowings of $4,936.1 million and gross repayments of $5,067.9 million. Our policy is to limit the amount of commercial paper we can issue by the amounts available under our Credit Facility up to an aggregate principal amount of $1.5 billion as mentioned above.

Our policy is to maintain availability at any time under our Credit Facilities amounts that are at least equal to the amount of commercial paper that we have outstanding at any time.

8. DEBT – (continued)

At June 30, 2016, we had approximately $414.1 million available under the terms of our Credit Facilities, determined as follows:

	(in millions)
Total commitments under our Credit Facilities	$2,600.0
Less: Amounts outstanding under our Credit Facilities	1,740.0
Principal amount of commercial paper outstanding	194.3
Letters of credit outstanding	251.6
Total amount available at June 30, 2016	$ 414.1

MEP Credit Agreement

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 $810.0 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. The MEP Credit Agreement's current maturity date is September 30, 2018; however, $140.0 million of commitments expire on the original maturity date of November 13, 2016, and an additional $25.0 million of commitments expire on September 30, 2017. During the six months ended June 30, 2016, MEP had net repayments of approximately $15.0 million, which includes gross borrowings of $3,790.0 million and gross repayments of $3,805.0 million.

Debt Covenants

As of June 30, 2016, we and our consolidated subsidiaries were 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, and the MEP Credit Agreement approximate their fair values at June 30, 2016, and December 31, 2015, respectively, due to the short-term nature and frequent repricing of the amounts outstanding under these obligations. The fair value of our outstanding commercial paper and borrowings under our Credit Facilities and the MEP Credit Agreement are included with our long-term debt obligations since we have the ability and the intent to refinance the amounts outstanding on a long-term basis.

The approximate fair value of our fixed-rate debt obligations was $6.6 billion and $5.9 billion at June 30, 2016, and December 31, 2015, 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.

9. 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 six months ended June 30, 2016.

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)				
April 29, 2016	May 6, 2016	May 13, 2016	$0.5830	$261.2	$44.3	$0.9	$216.0
January 29, 2016	February 5, 2016	February 12, 2016	$0.5830	$259.6	$42.7	$0.9	$216.0

(1) We issued 4,718,939 i-units to Enbridge Management, the sole owner of our i-units, during 2016 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.

9. PARTNERS' CAPITAL – (continued)

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 six months ended June 30, 2016 and 2015.

	For the six months ended June 30,	
	2016	2015
	(in millions)	
Series 1 Preferred interests		
Beginning balance	$1,186.8	$1,175.6
Net income	45.0	45.0
Accretion of discount on preferred units	2.3	8.0
Distribution payable	(45.0)	(45.0)
Ending balance	$1,189.1	$1,183.6
General and limited partner interests		
Beginning balance	$4,150.8	$4,156.2
Proceeds from issuance of partnership interests, net of costs	—	294.8
Net income	163.7	43.0
Distributions	(432.0)	(403.8)
Acquisition of noncontrolling interest in subsidiary	—	403.7
Ending balance	$3,882.5	$4,493.9
Accumulated other comprehensive loss		
Beginning balance	$ (370.0)	$ (211.4)
Changes in fair value of derivative financial instruments reclassified to earnings	19.8	(3.5)
Changes in fair value of derivative financial instruments recognized in other comprehensive loss	(139.1)	(44.1)
Ending balance	$ (489.3)	$ (259.0)
Noncontrolling interest		
Beginning balance	$3,944.5	$3,609.0
Capital contributions	63.4	502.6
Acquisition of noncontrolling interest in subsidiary	—	(403.7)
Other comprehensive income (loss) allocated to noncontrolling interest	—	(2.6)
Net income	139.1	61.3
Distributions to noncontrolling interest	(15.2)	(171.2)
Ending balance	$4,131.8	$3,595.4
Total partners' capital at end of period	$8,714.1	$9,013.9

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 six months ended June 30, 2016, 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 $223.3 million and $48.4 million, respectively, to cure the deficit balances in the Class A and Class B common units.

9. PARTNERS' CAPITAL – (continued)

Noncontrolling Interests

We have noncontrolling interests in the following consolidated subsidiaries: OLP, NDPC, and MEP. The noncontrolling interest in the OLP arises from the joint funding arrangements with our General Partner and its affiliate to finance certain expansion projects on our Lakehead system, which we refer to as the Eastern Access and Mainline Expansion Projects. Noncontrolling interest in NDPC arises from our agreement with Williston, an affiliate of MPC, to, among other things, fund 37.5% of the Sandpiper Project. Noncontrolling interest in MEP arises from its public unitholders' ownership interests in MEP.

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 June 30,		For the six months ended June 30,	
	2016	2015	2016	2015
	(in millions)			
Alberta Clipper Interests	$ —	$ —	$ —	$ (0.8)
Eastern Access Interests	53.2	45.1	104.7	89.9
U.S. Mainline Expansion Interests	34.1	27.9	60.7	44.4
Midcoast Energy Partners, L.P.	(17.0)	(63.0)	(26.3)	(72.2)
Total	$ 70.3	$ 10.0	$139.1	$ 61.3

10. 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 $15.8 million and $12.0 million for the six months ended June 30, 2016 and 2015, respectively, that we recorded as additions to "Property, plant and equipment, net" on our consolidated statements of financial position.

Sale of Accounts Receivable

We sold and derecognized receivables of $781.0 million and $917.8 million for the three months ended June 30, 2016 and 2015, respectively, and $1,633.5 million and $2,013.7 million for the six months ended June 30, 2016 and 2015, respectively, to an indirect, wholly-owned subsidiary of Enbridge. We received cash proceeds of $780.7 million and $917.5 million for the three months ended June 30, 2016 and 2015, respectively, and $1,632.8 million and $2,013.1 million for the six months ended June 30, 2016 and 2015, 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 and six months ended June 30, 2016 and 2015, the expense stemming from the discount on the receivables sold was not material.

10. RELATED PARTY TRANSACTIONS – (continued)

As of June 30, 2016 and December 31, 2015, we had $22.7 million and $19.0 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 June 30, 2016 and December 31, 2015, outstanding receivables of $238.8 million and $317.0 million, respectively, which had been sold and derecognized, had not been collected on behalf of the Enbridge subsidiary.

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 terminaling 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 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. Our equity investment in the Texas Express NGL system at June 30, 2016 and December 31, 2015, was $364.8 million and $372.3 million, respectively, which is included on our consolidated statements of financial position in ''Other assets, net.''

We recognized equity income of $6.6 million and $5.9 million for the three months ended June 30, 2016 and 2015, respectively, and $13.7 million and $11.6 million for the six months ended June 30, 2016 and 2015, respectively, in ''Other income'' on our consolidated statements of income related to our investment in the system.

We incurred $4.9 million and $4.6 million for the three months ended June 30, 2016 and 2015, respectively, and $10.3 million and $8.3 million for the six months ended June 30, 2016 and 2015, 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.

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 through 2022. The current commitment level is 29,000 Bpd.

Financing Transactions with Affiliates

Distribution from MEP

The following table presents distributions paid by MEP during the six months ended June 30, 2016, 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 the noncontrolling interest	Total MEP Distribution
			(in millions)	
April 28, 2016	May 13, 2016	$ 8.9	$ 7.6	$16.5
January 28, 2016	February 12, 2016	$ 8.9	$ 7.6	$16.5
		$17.8	$15.2	$33.0

Omnibus Agreement

We, Midcoast Holdings, MEP and Enbridge are parties to the Omnibus Agreement under which we agreed to, among other things, indemnify MEP for certain matters, including environmental, right-of-way and permit matters. Our obligation to indemnify MEP for these matters is subject to a $500,000 aggregate deductible before MEP is

10. RELATED PARTY TRANSACTIONS – (continued)

entitled to indemnification. Additionally, there is a $15.0 million aggregate cap on the amounts for which we will indemnify MEP for under the Omnibus Agreement. During the first quarter of 2016, we paid indemnification proceeds to MEP under the Omnibus Agreement of $12.2 million for the acquisition of title to right-of-way assets that were pending at the time of MEP's initial public offering and associated legal fees. No other payments have been made to MEP under the Omnibus Agreement.

Financial Support Agreement

At June 30, 2016, we had no letters of credit outstanding and $15.3 million of guarantees to Midcoast Operating under a Financial Support Agreement with Midcoast Operating. At December 31, 2015, we provided $7.5 million of letters of credit outstanding and $21.7 million of guarantees to Midcoast Operating under this agreement.

Amendment of OLP Limited Partnership Agreement

On July 30, 2015, the partners amended and restated the limited partnership agreement of the OLP, pursuant to which our General Partner agreed to temporarily forego Series EA and ME, collectively, the Series, distributions commencing in the quarter ended June 30, 2015 through the quarter ended March 31, 2016. The General Partner's capital funding contribution requirements for each of those two Series, commencing in August 2015, will be reduced by the amount of its foregone cash distributions from the respective Series, until the earlier of December 31, 2016 and the date aggregate reductions in capital contributions for such Series are equal to the foregone cash distributions for such Series. To the extent that the General Partner's portion of capital contributions prior to December 31, 2016 are insufficient to cover the General Partner's foregone cash distributions for a Series, beginning with the distribution related to the first quarter of 2017 for that Series, we will receive reduced cash distributions by up to 50%, and the General Partner will receive a comparable increase in cash distributions each quarter until the General Partner has received an aggregate amount of contribution reductions and distribution increases equal to the amount of foregone cash distributions.

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. Our General Partner owns 75% of the EA interests, and, except as described above in *Amendment of OLP Limited Partnership Agreement*, the projects are jointly funded by our General Partner at 75% and us at 25%.

Our General Partner made equity contributions totaling $7.2 million and $98.3 million to the OLP for the six months ended June 30, 2016 and 2015, 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 six months ended June 30, 2016, 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 the noncontrolling interest	Total Series EA Distribution
			(in millions)	
April 29, 2016	May 13, 2016	$ 79.0	$—	$ 79.0
January 29, 2016	February 12, 2016	$ 79.2	$—	$ 79.2
		$158.2	$—	$158.2

10. RELATED PARTY TRANSACTIONS – (continued)

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, except as described above in *Amendment of OLP Limited Partnership Agreement*, the projects are jointly funded by our General Partner at 75% and us at 25%, under the Mainline Expansion Joint Funding Agreement, which is similar to the Eastern Access Joint Funding Agreement.

Our General Partner has made equity contributions totaling $42.8 million and $360.7 million to the OLP for the six months ended June 30, 2016, and 2015, 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 six months ended June 30, 2016, 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 the noncontrolling interest	Total Series ME Distribution
			(in millions)	
April 29, 2016	May 13, 2016	$43.2	$—	$43.2
January 29, 2016	February 12, 2016	$40.8	$—	$40.8
		$84.0	$—	$84.0

11. 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 June 30, 2016 and December 31, 2015, we had $110.3 million and $95.8 million, respectively, included in ''Environmental liabilities,'' and $55.2 million and $64.0 million, respectively, included in ''Other long-term liabilities,'' on our consolidated statements of financial position that we have accrued for costs we have recognized primarily 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

11. COMMITMENTS AND CONTINGENCIES – (continued)

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 perform necessary remediation, 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 June 30, 2016, our cumulative cost estimate for the Line 6B crude oil release remains at $1.2 billion. This includes a reduction of estimated remediation efforts offset by an increase in estimated civil penalties under the Clean Water Act of the United States, as described below under *Fines and Penalties*.

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 June 30, 2016. Our estimates exclude: (1) amounts we have capitalized, (2) any claims associated with the release that may later become evident, (3) amounts recoverable under insurance, and (4) 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 material 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:

	(in millions)
Response personnel and equipment	$ 548.6
Environmental consultants	226.9
Professional, regulatory, fines and penalties and other	447.5
Total	$1,223.0

For the six months ended June 30, 2016 and 2015, we made payments of $12.9 million and $20.1 million, respectively, for costs associated with the Line 6B crude oil release. As of June 30, 2016 and December 31, 2015, we had a remaining estimated liability of $154.7 million and $149.8 million, respectively.

Line 6B Fines and Penalties

At June 30, 2016, 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.

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, that 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 Line 6A. The Consent Decree will take effect upon approval by the Court, following a comment period.

11. COMMITMENTS AND CONTINGENCIES – (continued)

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. 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 Line 6B crude oil release, excluding costs for fines and penalties.

A majority of the costs incurred for the Line 6B crude oil release, other than fines and penalties, are covered by the insurance policy 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 June 30, 2016, costs related to Line 6B exceeded the limits of the coverage available under this insurance policy. As of June 30, 2016, 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. We will record receivables for additional amounts we claim for recovery pursuant to our insurance policies during the period that we deem realization of the claim for recovery to be probable.

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 is not scheduled to occur until fourth quarter of 2016. While we believe that those costs are eligible for recovery, there can be no assurance that we will prevail.

Enbridge, together with us and its other affiliates, renewed its comprehensive property and liability insurance programs, under which we are insured through April 30, 2017, with a liability program aggregate limit of $900.0 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, MEP, and other Enbridge subsidiaries.

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. Three 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.

11. COMMITMENTS AND CONTINGENCIES – (continued)

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.

12. 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 NGLs 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:

	June 30, 2016	December 31, 2015
	(in millions)	
Other current assets	$ 63.2	$ 123.9
Other assets, net	12.2	39.7
Accounts payable and other[1]	(170.0)	(130.9)
Other long-term liabilities	(169.0)	(90.6)
	$(263.6)	$ (57.9)

(1) Includes $12.6 million held of cash collateral at December 31, 2015.

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

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

	June 30, 2016	December 31, 2015
	(in millions)	
Counterparty Credit Quality[1]		
AA[2]	(91.0)	(12.4)
A	(106.7)	(10.5)
Lower than A	(65.9)	(35.0)
	$(263.6)	$(57.9)

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

(2) Includes $12.6 million held of cash collateral at December 31, 2015.

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

As the net value of our derivative financial instruments has decreased in response to changes in forward commodity prices and interest rates, our outstanding financial exposure to third parties has also decreased. When credit thresholds are met pursuant to the terms of our International Swaps and Derivatives Association, Inc., or ISDA®, financial contracts, we have the right to require collateral from our counterparties. We include any cash collateral received or posted in the balances listed above. At June 30, 2016, we did not have any cash collateral on our asset exposures. At December 31, 2015, we held $12.6 million of 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 $250.0 million and $120.1 million relating to our liability exposures pursuant to the margin thresholds in effect at June 30, 2016 and December 31, 2015, 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 June 30, 2016, we would have been required to provide additional letters of credit in the amount of $61.0 million related to our positions.

At June 30, 2016 and December 31, 2015, we had credit concentrations in the following industry sectors, as presented below:

	June 30, 2016	December 31, 2015
	(in millions)	
United States financial institutions and investment banking entities[1]	$(163.0)	$(30.9)
Non-United States financial institutions	(111.3)	(51.0)
Other	10.7	24.0
	$(263.6)	$(57.9)

(1) Includes $12.6 million held of cash collateral at December 31, 2015.

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

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	June 30, 2016	December 31, 2015	June 30, 2016	December 31, 2015
		(in millions)			
Derivatives designated as hedging instruments:[1]					
Interest rate contracts	Accounts payable and other	$ —	$ —	$(138.2)	$ (85.2)
Interest rate contracts	Other long-term liabilities	—	—	(158.0)	(72.3)
		—	—	(296.2)	(157.5)
Derivatives not designated as hedging instruments:					
Commodity contracts	Other current assets	63.2	123.9	—	—
Commodity contracts	Other assets	12.2	39.7	—	—
Commodity contracts	Accounts payable and other[2]	—	—	(31.8)	(33.1)
Commodity contracts	Other long-term liabilities	—	—	(11.0)	(18.3)
		75.4	163.6	(42.8)	(51.4)
Total derivative instruments		$75.4	$163.6	$(339.0)	$(208.9)

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

(2) Liability derivatives exclude $12.6 million held of cash collateral at December 31, 2015.

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 June 30, 2016 and December 31, 2015, we included in AOCI unrecognized losses of approximately $239.6 million and $255.5 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.

During the six months ended June 30, 2015, unrealized commodity hedge gains of $0.6 million were de-designated as a result of the hedges no longer meeting hedge accounting criteria. At June 30, 2016, we had no de-designated commodity hedges. We estimate that approximately $53.1 million, representing net losses from our cash flow hedging activities based on pricing and positions at June 30, 2016, will be reclassified from AOCI to earnings during the next 12 months.

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

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 June 30, 2016					
Interest rate contracts	$ (49.6)	Interest expense	$ (9.8)	Interest expense	$ (1.5)
Commodity contracts	—	Commodity Costs	—	Commodity Costs	—
Total	$ (49.6)		$ (9.8)		$ (1.5)
For the three months ended June 30, 2015					
Interest rate contracts	$ 103.2	Interest expense	$ (2.9)	Interest expense	$ 3.7
Commodity contracts	(7.7)	Commodity Costs	7.1	Commodity Costs	—
Total	$ 95.5		$ 4.2		$ 3.7
For the six months ended June 30, 2016					
Interest rate contracts	$(135.2)	Interest expense	$(19.9)	Interest expense	$ (3.4)
Commodity contracts	—	Commodity Costs	0.1	Commodity Costs	—
Total	$(135.2)		$(19.8)		$ (3.4)
For the six months ended June 30, 2015					
Interest rate contracts	$ (42.0)	Interest expense	$ (8.3)	Interest expense	$32.4
Commodity contracts	(11.3)	Commodity Costs	15.5	Commodity Costs	(4.0)
Total	$ (53.3)		$ 7.2		$28.4

(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	
	2016	2015
	(in millions)	
Balance at January 1	$(370.0)	$(211.4)
Other comprehensive loss before reclassifications[1]	(139.1)	(44.1)
Amounts reclassified from AOCI[2][3]	19.8	(3.5)
Net other comprehensive loss	$(119.3)	$ (47.6)
Balance at June 30	$(489.3)	$(259.0)

(1) Excludes NCI gain of $1.1 million reclassified from AOCI at June 30, 2015.

(2) Excludes NCI loss of $3.7 million reclassified from AOCI at June 30, 2015.

(3) For additional details on the amounts reclassified from AOCI, reference the *Reclassifications from Accumulated Other Comprehensive Income* table below.

Reclassifications from Accumulated Other Comprehensive Income

	For the three months ended June 30,		For the six months ended June 30,	
	2016	2015	2016	2015
	(in millions)			
Losses (gains) on cash flow hedges:				
Interest Rate Contracts[1]	$ 9.9	$ 2.9	$19.9	$ 8.3
Commodity Contracts[2][3][4]	(0.1)	(5.4)	(0.1)	(11.8)
Total Reclassifications from AOCI	$ 9.8	$(2.5)	$19.8	$ (3.5)

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

(2) Gains reported within "Commodity costs" in the consolidated statements of income.

(3) Excludes NCI loss of $1.7 million reclassified from AOCI for the three months ending June 30, 2015.

(4) Excludes NCI loss of $3.7 million reclassified from AOCI for the six months ended June 30, 2015.

12. 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 June 30, 2016	For the three months ended June 30, 2015	For the six months ended June 30, 2016	For the six months ended June 30, 2015
		Amount of Gain or (Loss) Recognized in Earnings[1][2]		Amount of Gain or (Loss) Recognized in Earnings[1][2]	
		(in millions)			
Commodity contracts . . .	Transportation and other services[3]	$ (3.9)	$(2.7)	$ (3.1)	$ —
Commodity contracts . . .	Commodity sales	(1.1)	2.1	(3.5)	(15.2)
Commodity contracts . . .	Commodity sales – affiliate	—	(0.1)	—	(0.3)
Commodity contracts . . .	Commodity costs[4]	(26.6)	(8.6)	(24.8)	3.5
Total		$(31.6)	$(9.3)	$(31.4)	$(12.0)

(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 $1.2 million and $5.6 million for the three months ended June 30, 2016 and 2015, respectively and settlement gains of $3.7 million and $12.2 million for the six months ended June 30, 2016 and 2015, respectively.

(4) Includes settlement gains of $18.1 million and $18.0 million for the three months ended June 30, 2016 and 2015, respectively and settlement gains of $44.6 million and $43.7 million for the six months ended June 30, 2016 and 2015, 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 June 30, 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	$75.4	$—	$75.4	$(26.1)	$49.3

	As of December 31, 2015				
	Gross Amount of Recognized Assets	Gross Amount Offset in the Statement of Financial Position	Net Amount of Assets Presented in the Statement of Financial Position	Gross Amount Not Offset in the Statement of Financial Position[1]	Net Amount
			(in millions)		
Description:					
Derivatives	$163.6	$—	$163.6	$(41.5)	$122.1

(1) Includes $12.6 million of cash collateral held at December 31, 2015.

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

Offsetting of Financial Liabilities and Derivative Liabilities

	As of June 30, 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	$(339.0)	$—	$(339.0)	$26.1	$(312.9)

	As of December 31, 2015				
	Gross Amount of Recognized Liabilities[(1)]	Gross Amount Offset in the Statement of Financial Position	Net Amount of Liabilities Presented in the Statement of Financial Position	Gross Amount Not Offset in the Statement of Financial Position[(1)]	Net Amount
			(in millions)		
Description:					
Derivatives	$(221.5)	$—	$(221.5)	$41.5	$(180.0)

(1) Includes $12.6 million of cash collateral held at December 31, 2015.

Inputs to Fair Value Derivative Instruments

The following table sets forth by level within the fair value hierarchy of our net financial assets and liabilities that were accounted for at fair value on a recurring basis as of June 30, 2016 and December 31, 2015. We classify financial assets and liabilities in their entirety based on the lowest level of input that is significant to the fair value measurement. Our assessment of the significance of a particular input to the fair value measurement requires judgment and may affect our valuation of the financial assets and liabilities and their placement within the fair value hierarchy.

	June 30, 2016				December 31, 2015			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
				(in millions)				
Interest rate contracts . . .	$—	$(296.2)	$ —	$(296.2)	$—	$(157.5)	$ —	$(157.5)
Commodity contracts:								
Financial	—	0.2	0.7	0.9	—	8.4	8.9	17.3
Physical	—	—	(0.5)	(0.5)	—	—	0.6	0.6
Commodity options	—	—	32.2	32.2	—	—	94.3	94.3
	$—	(296.0)	$32.4	$(263.6)	$—	$(149.1)	$103.8	$ (45.3)
Cash collateral				—				(12.6)
Total				$(263.6)				$ (57.9)

Qualitative Information about Level 2 Fair Value Measurements

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

12. 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 June 30, 2016	Valuation Technique	Unobservable Input	Range[1]			Units
				Lowest	Highest	Weighted Average	
	(in millions)						
Commodity Contracts – Financial							
Natural Gas	$ 1.4	Market Approach	Forward Gas Price	2.74	3.73	3.22	MMBtu
NGLs	(0.7)	Market Approach	Forward NGL Price	0.24	1.03	0.50	Gal
Commodity Contracts – Physical							
Natural Gas	(0.4)	Market Approach	Forward Gas Price	2.56	3.34	2.83	MMBtu
Crude Oil	(2.2)	Market Approach	Forward Crude Price	35.22	51.13	47.24	Bbl
NGLs	2.1	Market Approach	Forward NGL Price	0.24	1.44	0.55	Gal
Commodity Options							
Natural Gas, Crude and NGLs	32.2	Option Model	Option Volatility	7%	91%	37%	
Total Fair Value	$32.4						

(1) Prices are in dollars per Millions of British Thermal Units, or MMBtu, for natural gas; dollars per gallon, or Gal, for NGLs; and dollars per barrel, or Bbl, for crude oil.

Quantitative Information About Level 3 Fair Value Measurements

Contract Type	Fair Value at December 31, 2015[2]	Valuation Technique	Unobservable Input	Range[1]			Units
				Lowest	Highest	Weighted Average	
	(in millions)						
Commodity Contracts – Financial							
Natural Gas	$ 0.3	Market Approach	Forward Gas Price	2.27	3.07	2.64	MMBtu
NGLs	8.6	Market Approach	Forward NGL Price	0.16	0.93	0.41	Gal
Commodity Contracts – Physical							
Natural Gas	(2.5)	Market Approach	Forward Gas Price	2.08	3.44	2.33	MMBtu
Crude Oil	—	Market Approach	Forward Crude Price	26.50	38.41	37.29	Bbl
NGLs	3.1	Market Approach	Forward NGL Price	0.16	1.20	0.40	Gal
Commodity Options							
Natural Gas, Crude and NGLs	94.3	Option Model	Option Volatility	13%	74%	36%	
Total Fair Value	$103.8						

(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 losses of approximately $0.3 million.

12. 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, 2016 to June 30, 2016. 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, 2016	$ 8.9	$ 0.6	$ 94.3	$103.8
Transfer in (out) of Level 3[1]	—	—	—	—
Gains or losses included in earnings:				
Reported in Commodity sales	—	(14.5)	—	(14.5)
Reported in Commodity costs	(1.9)	16.9	(23.8)	(8.8)
Gains or losses included in other comprehensive income:				
Purchases, issuances, sales and settlements:				
Purchases	—	—	—	—
Sales	—	—	0.7	0.7
Settlements[2]	(6.3)	(3.5)	(39.0)	(48.8)
Ending balance as June 30, 2016	$ 0.7	$ (0.5)	$ 32.2	$ 32.4
Amounts reported in Commodity sales	$ —	$ (3.5)	$ —	$ (3.5)
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	$ —	$ (4.4)	$ —	$ (4.4)
Reported in Commodity costs	$(2.4)	$ 4.6	$(20.8)	(18.6)

(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.

12. 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 June 30, 2016 and December 31, 2015.

	At June 30, 2016						At December 31, 2015	
			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 2016								
Swaps								
Receive variable/pay fixed	Natural Gas	16,287	$ 3.08	$ 3.48	$—	$ —	$ —	$ —
	NGL	1,203,400	$30.79	$31.48	$1.4	$(2.2)	$ 0.2	$ (8.4)
	Crude Oil	304,800	$49.52	$66.64	$0.3	$(5.6)	$ —	$(17.5)
Receive fixed/pay variable	NGL	2,513,400	$23.59	$22.79	$5.7	$(3.7)	$18.3	$ (0.2)
	Crude Oil	831,672	$57.16	$49.39	$8.2	$(1.7)	$25.4	$ —
Receive variable/pay variable	Natural Gas	6,536,000	$ 3.18	$ 3.15	$0.3	$(0.1)	$ 0.1	$ (0.1)
Physical Contracts								
Receive variable/pay fixed	NGL	535,284	$26.41	$23.91	$1.4	$(0.1)	$ —	$ (0.2)
	Crude Oil	—	$ —	$ —	$—	$ —	$ —	$ (0.2)
Receive fixed/pay variable	NGL	1,165,923	$19.12	$21.91	$0.2	$(3.4)	$ 1.9	$ (0.2)
Receive variable/pay variable	Natural Gas	68,727,634	$ 2.77	$ 2.78	$0.1	$(0.8)	$ —	$ (2.8)
	NGL	6,459,247	$22.70	$22.22	$3.8	$(0.7)	$ 4.0	$ (2.4)
	Crude Oil	949,604	$44.46	$46.75	$1.0	$(3.1)	$ 0.7	$ (0.5)
Portion of contracts maturing in 2017								
Swaps								
Receive variable/pay fixed	Natural Gas	76,530	$ 2.97	$ 2.97	$—	$ —	$ —	$ —
	NGL	1,042,500	$20.93	$21.52	$1.0	$(1.6)	$ —	$ (4.5)
	Crude Oil	638,750	$52.41	$64.29	$0.2	$(7.8)	$ —	$(10.9)
Receive fixed/pay variable	NGL	1,452,500	$18.84	$19.86	$0.7	$(2.2)	$ 3.3	$ (0.1)
	Crude Oil	866,510	$59.89	$52.41	$7.7	$(1.4)	$10.9	$ —
Receive variable/pay variable	Natural Gas	12,550,000	$ 3.25	$ 3.16	$1.2	$(0.1)	$ 0.5	$ (0.2)
Physical Contracts								
Receive variable/pay fixed	NGL	45,000	$23.80	$21.95	$0.1	$ —	$ —	$ —
Receive fixed/pay variable	NGL	10,820	$28.00	$25.09	$—	$ —	$ —	$ —
Receive variable/pay variable	Natural Gas	10,067,810	$ 3.12	$ 3.10	$0.2	$ —	$ 0.1	$ —
	NGL	792,372	$28.42	$27.37	$0.9	$ —	$ —	$ —
Portion of contracts maturing in 2018								
Physical Contracts								
Receive variable/pay variable	Natural Gas	2,187,810	$ 3.04	$ 3.01	$0.1	$ —	$ 0.1	$ —
Portion of contracts maturing in 2019								
Physical Contracts								
Receive variable/pay variable	Natural Gas	2,187,810	$ 3.04	$ 3.01	$0.1	$ —	$ 0.1	$ —
Portion of contracts maturing in 2020								
Physical Contracts								
Receive variable/pay variable	Natural Gas	359,640	$ 3.29	$ 3.27	$—	$ —	$ —	$ —

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

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

(3) The fair value is determined based on quoted market prices at June 30, 2016 and December 31, 2015, 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 $0.3 million and $0.5 million at June 30, 2016 and December 31, 2015, respectively, as well as cash collateral received.

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

The following table provides summarized information about the fair values of expected cash flows of our outstanding commodity options at June 30, 2016 and December 31, 2015.

	At June 30, 2016						At December 31, 2015	
					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 2016								
Puts (purchased)	Natural Gas	828,000	$ 3.75	$ 3.02	$ 0.6	$ —	$ 2.1	$ —
	NGL	1,490,400	$39.29	$27.02	$19.2	$ —	$54.4	$ —
	Crude Oil	404,800	$75.91	$49.95	$10.5	$ —	$27.7	$ —
Calls (written)	Natural Gas	828,000	$ 4.98	$ 3.02	$ —	$ —	$ —	$ —
	NGL	1,490,400	$45.09	$27.02	$ —	$(0.5)	$ —	$(0.3)
	Crude Oil	404,800	$86.68	$49.95	$ —	$ —	$ —	$ —
Puts (written)	Natural Gas	828,000	$ 3.75	$ 3.02	$ —	$(0.6)	$ —	$(2.1)
	NGL	119,600	$37.04	$28.02	$ —	$(1.2)	$ —	$(1.5)
Calls (purchased)	Natural Gas	828,000	$ 4.98	$ 3.02	$ —	$ —	$ —	$ —
	NGL	119,600	$42.09	$28.02	$ 0.1	$ —	$ —	$ —
Portion of option contracts maturing in 2017								
Puts (purchased)	NGL	1,642,500	$25.90	$28.66	$ 3.3	$ —	$ 5.8	$ —
	Crude Oil	638,750	$59.86	$52.41	$ 7.8	$ —	$10.0	$ —
Calls (written)	NGL	1,642,500	$30.06	$28.66	$ —	$(4.7)	$ —	$(0.8)
	Crude Oil	638,750	$68.19	$52.41	$ —	$(1.7)	$ —	$(0.6)
Portion of option contracts maturing in 2018								
Puts (purchased)	Crude Oil	91,250	$42.00	$53.81	$ 0.3	$ —	$ —	$ —
Calls (written)	Crude Oil	91,250	$51.75	$53.81	$ —	$(0.8)	$ —	$ —

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

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

(3) The fair value is determined based on quoted market prices at June 30, 2016 and December 31, 2015, respectively, discounted using the swap rate for the respective periods to consider the time value of money. Fair values exclude credit valuation adjustment losses of approximately $0.1 million and $0.4 million at June 30, and December 31, 2015, respectively, as well as cash collateral received.

12. 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.

Date of Maturity & Contract Type	Accounting Treatment	Notional	Average Fixed Rate[1]	Fair Value[2] at June 30, 2016	Fair Value[2] at December 31, 2015
			(dollars in millions)		
Contracts maturing in 2017					
Interest Rate Swaps – Pay Fixed	Cash Flow Hedge	$500	2.21%	$ (4.2)	$ (7.0)
Contracts maturing in 2018					
Interest Rate Swaps – Pay Fixed	Cash Flow Hedge	$810	2.24%	$ (12.8)	$ (6.6)
Contracts maturing in 2019					
Interest Rate Swaps – Pay Fixed	Cash Flow Hedge	$620	2.96%	$ (12.5)	$ (6.0)
Contracts settling prior to maturity					
2016 – Pre-issuance Hedges	Cash Flow Hedge	$500	4.21%	$(129.8)	$(80.4)
2017 – Pre-issuance Hedges	Cash Flow Hedge	$500	3.69%	$ (97.9)	$(49.2)
2018 – Pre-issuance Hedges	Cash Flow Hedge	$350	3.08%	$ (43.7)	$(12.2)

(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 June 30, 2016 and December 31, 2015, 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 $4.7 million and $3.9 million at June 30, 2016 and December 31, 2015, respectively.

13. 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 0.4% for the six months ended June 30, 2016 and 2015.

At June 30, 2016 and December 31, 2015, we included a current income tax payable of $1.4 million and $1.1 million, respectively, in ‘‘Property and other taxes payable’’ on our consolidated statements of financial position. In addition, at June 30, 2016 and December 31, 2015, we included a deferred income tax payable of $21.9 million and $20.9 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.

14. 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.

14. SEGMENT INFORMATION – (continued)

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

	For the three months ended June 30, 2016			
	Liquids	Natural Gas	Corporate[1]	Total
	(in millions)			
Operating revenues:[2]				
Commodity sales	$ —	$380.8	$ —	$ 380.8
Transportation and other services	621.3	46.8	—	668.1
	621.3	427.6	—	1,048.9
Operating expenses:				
Commodity costs	—	359.1	—	359.1
Environmental costs, net of recoveries	0.1	—	—	0.1
Operating and administrative	132.1	78.0	2.7	212.8
Power	59.7	—	—	59.7
Asset impairment	—	10.6	—	10.6
Depreciation and amortization	104.9	40.0	—	144.9
	296.8	487.7	2.7	787.2
Operating income (loss)	324.5	(60.1)	(2.7)	261.7
Interest expense, net	—	—	(101.5)	(101.5)
Allowance for equity used during construction	—	—	13.3	13.3
Other income	—	6.6[3]	0.1	6.7
Income (loss) before income tax expense	324.5	(53.5)	(90.8)	180.2
Income tax expense	—	—	(2.5)	(2.5)
Net income (loss)	324.5	(53.5)	(93.3)	177.7
Less: Net income attributable to:				
Noncontrolling interest	—	—	70.3	70.3
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.	$324.5	$ (53.5)	$(187.3)	$ 83.7

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

(2) There were no intersegment revenues for the three months ended June 30, 2016.

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

14. SEGMENT INFORMATION – (continued)

	For the three months ended June 30, 2015			
	Liquids	Natural Gas	Corporate[1]	Total
	(in millions)			
Operating revenues:[2]				
Commodity sales	$ —	$ 731.1	$ —	$ 731.1
Transportation and other services	533.0	49.0	—	582.0
	533.0	780.1	—	1,313.1
Operating expenses:				
Commodity costs	—	670.6	—	670.6
Environmental costs, net of recoveries	(0.8)	—	—	(0.8)
Operating and administrative	116.3	87.3	3.6	207.2
Power	57.2	—	—	57.2
Goodwill impairment	—	246.7	—	246.7
Asset impairment	—	12.3	—	12.3
Depreciation and amortization	88.7	40.8	—	129.5
	261.4	1,057.7	3.6	1,322.7
Operating income (loss)	271.6	(277.6)	(3.6)	(9.6)
Interest expense, net	—	—	(78.0)	(78.0)
Allowance for equity used during construction	—	—	17.3	17.3
Other income	—	5.9[3]	0.1	6.0
Income (loss) before income tax benefit	271.6	(271.7)	(64.2)	(64.3)
Income tax benefit	—	—	3.8	3.8
Net income (loss)	271.6	(271.7)	(60.4)	(60.5)
Less: Net income attributable to:				
Noncontrolling interest	—	—	10.0	10.0
Series 1 preferred unit distributions	—	—	22.5	22.5
Accretion of discount on Series 1 preferred units	—	—	4.1	4.1
Net income (loss) attributable to general and limited partner ownership interests in Enbridge Energy Partners, L.P.	$271.6	$ (271.7)	$(97.0)	$ (97.1)

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

(2) There were no intersegment revenues for the three months ended June 30, 2015.

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

14. SEGMENT INFORMATION – (continued)

	As of and for the six months ended June 30, 2016			
	Liquids	Natural Gas	Corporate(1)	Total
	(in millions)			
Operating revenues:(2)				
Commodity sales	$ —	$ 763.8	$ —	$ 763.8
Transportation and other services	1,251.0	95.7	—	1,346.7
	1,251.0	859.5	—	2,110.5
Operating expenses:				
Commodity costs	—	707.1	—	707.1
Environmental costs, net of recoveries	17.0	—	—	17.0
Operating and administrative	268.9	152.3	6.2	427.4
Power	132.5	—	—	132.5
Asset impairment	0.4	10.6	—	11.0
Depreciation and amortization	206.3	79.5	—	285.8
	625.1	949.5	6.2	1,580.8
Operating income (loss)	625.9	(90.0)	(6.2)	529.7
Interest expense, net	—	—	(214.4)	(214.4)
Allowance for equity used during construction	—	—	25.6	25.6
Other income	—	13.7(3)	0.5	14.2
Income (loss) before income tax expense	625.9	(76.3)	(194.5)	355.1
Income tax expense	—	—	(5.0)	(5.0)
Net income (loss)	625.9	(76.3)	(199.5)	350.1
Less: Net income attributable to:				
Noncontrolling interest	—	—	139.1	139.1
Series 1 preferred unit distributions	—	—	45.0	45.0
Accretion of discount on Series 1 preferred units	—	—	2.3	2.3
Net income (loss) attributable to general and limited partner ownership interests in Enbridge Energy Partners, L.P.	$ 625.9	$ (76.3)	$(385.9)	$ 163.7
Total assets	$13,822.4	$4,952.8(4)	$ 138.3	$18,913.5
Capital expenditures (excluding acquisitions)	$ 470.9	$ 28.0	$ 0.7	$ 499.6

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

(2) There were no intersegment revenues for the six months ended June 30, 2016.

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

(4) Total assets for our Natural Gas segment includes $364.8 million for our equity investment in the Texas Express NGL system.

14. SEGMENT INFORMATION – (continued)

	As of and for the six months ended June 30, 2015			
	Liquids	Natural Gas	Corporate[1]	Total
	(in millions)			
Operating revenues:[2]				
Commodity sales	$ —	$1,553.8	$ —	$ 1,553.8
Transportation and other services	1,088.1	99.8	—	1,187.9
	1,088.1	1,653.6	—	2,741.7
Operating expenses:				
Commodity costs	—	1,449.7	—	1,449.7
Environmental costs, net of recoveries	—	—	—	—
Operating and administrative	246.7	170.0	7.6	424.3
Power	120.8	—	—	120.8
Goodwill impairment	—	246.7	—	246.7
Asset impairment	—	12.3	—	12.3
Depreciation and amortization	178.8	79.1	—	257.9
	546.3	1,957.8	7.6	2,511.7
Operating income (loss)	541.8	(304.2)	(7.6)	230.0
Interest expense, net	—	—	(126.3)	(126.3)
Allowance for equity used during construction	—	—	40.3	40.3
Other income	—	11.6[3]	0.3	11.9
Income (loss) before income tax benefit	541.8	(292.6)	(93.3)	155.9
Income tax benefit	—	—	1.4	1.4
Net income (loss)	541.8	(292.6)	(91.9)	157.3
Less: Net income attributable to:				
Noncontrolling interest	—	—	61.3	61.3
Series 1 preferred unit distributions	—	—	45.0	45.0
Accretion of discount on Series 1 preferred units	—	—	8.0	8.0
Net income (loss) attributable to general and limited partner ownership interests in Enbridge Energy Partners, L.P.	$ 541.8	$ (292.6)	$(206.2)	$ 43.0
Total assets	$12,563.3	$5,256.5[4]	$ 173.3	$17,993.1
Capital expenditures (excluding acquisitions)	$ 909.0	$ 104.6	$ 13.9	$ 1,027.5

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

(2) There were no intersegment revenues for the six months ended June 30, 2015.

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

(4) Total assets for our Natural Gas segment includes $376.2 million for our equity investment in the Texas Express NGL system.

15. SUPPLEMENTAL CASH FLOWS INFORMATION

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

	For the six months ended June 30,	
	2016	2015
	(in millions)	
Total capital expenditures (excluding ‘‘Investment in joint venture’’)	$499.6	$1,027.5
(Increase) decrease in construction payables	178.5	(32.6)
Cash used for additions to property, plant and equipment	$678.1	$ 994.9

16. REGULATORY MATTERS

Regulatory Accounting

Due to over or under recovery adjustments made in accordance with the FERC’s 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 and six months ended June 30, 2016 and 2015 are as follows:

	For the three months ended June 30,		For the six months ended June 30,	
	2016	2015	2016	2015
	(in millions)			
Net regulatory asset (liability) balance at beginning of period	$31.2	$(6.8)	$ 29.9	$ 6.0
Current period under recovery revenue adjustments	5.9	9.6	13.6	0.5
Amortization of prior year regulatory liability	(7.8)	(0.8)	(14.2)	(4.5)
Net regulatory asset balance at end of period	$29.3	$ 2.0	$ 29.3	$ 2.0

Other Contractual Obligations

Qualifying Volumes

We have certain contractual obligations with our customers in which a portion of the revenue earned on volumes above certain predetermined shipment levels, or qualifying volumes, are returned to the shippers through future rate adjustments. At June 30, 2016 and December 31, 2015 we had no qualifying volume liabilities related to the original Southern Access and Alberta Clipper agreements on our consolidated statements of financial position.

We amortize the liability on a straight-line basis as an adjustment to revenue in the following year, reflecting the related rate adjustment. There was no amortization for qualifying volume liabilities for the three and six months ended June 30, 2016 and 2015.

Alberta Clipper Pipeline Property Taxes

A portion of the rates we charge our customers includes an estimate for annual property taxes. If the estimated property tax we collect from our customers is higher or lower than the actual property tax imposed, we are contractually obligated to refund to our customers or entitled to collect from our customers 50% of the property tax over or under recovery, respectively. At June 30, 2016 and December 31, 2015, we had $0.7 million and $0.8 million, respectively, in property tax under recovery assets related to our Alberta Clipper Pipeline on our consolidated statements of financial position.

During 2015 and 2014, we incurred liabilities related to contractual obligations with our customers on the Alberta Clipper Pipeline related to property taxes. As a result, in 2015 and 2014, we recorded a liability for the

16. REGULATORY MATTERS – (continued)

contractual amounts due back to our shippers with the corresponding amount as a reduction to revenue. We amortized the liability on a straight-line basis as an adjustment to revenue in the following year, reflecting the related rate adjustment. For the three and six months ended June 30, 2016, we amortized through revenue $0.3 million and $0.1 million of property tax under recovery assets, respectively, on our consolidated statements of income with a corresponding amount reducing the contractual obligation on our consolidated statements of financial position. For the three and six months ended June 30, 2015, we amortized through revenue $1.5 million and $2.9 million of property tax over recovery liabilities, respectively, on our consolidated statements of income with a corresponding amount reducing the contractual obligation on our consolidated statements of financial position.

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 $13.3 million and $25.6 million of ‘‘Allowance for equity used during construction’’ on our consolidated statement of income for the three and six months ended June 30, 2016, respectively, and a corresponding amount of $25.6 million in ‘‘Property, plant and equipment, net’’ on our consolidated statement of financial position at June 30, 2016. We recorded $17.3 million and $40.3 million of ‘‘Allowance for equity used during construction’’ in our consolidated statements of income for the three and six months ended June 30, 2015, respectively, with a corresponding amount of $40.3 million in ‘‘Property, plant and equipment’’ on our consolidated statement of financial position at June 30, 2015.

17. RECENT ACCOUNTING PRONOUNCEMENTS NOT YET ADOPTED

Revenues from Contracts with Customers

Since May 2014, the FASB has issued Accounting Standards Update Nos. 2014-09, 2015-14, 2016-08, 2016-10 and 2016-12 which outline a single comprehensive model for entities to use in accounting for revenue arising from contracts with customers and supersedes most current revenue recognition guidance, including industry-specific guidance. The accounting updates are effective for annual and interim periods beginning on or after December 15, 2017, and may be applied on either a full or modified retrospective basis. We are in the early stages of reviewing our revenue contracts and are unable to estimate the impacts that this pronouncement will have on our consolidated financial statements at this time. We are also currently evaluating which transition approach we will apply.

Leases

In February 2016, the FASB issued Accounting Standards Update No. 2016-02, which requires lessees to recognize a right-of-use asset and a lease liability on the balance sheet for practically all leases (other than leases that are less than 12 months). The pronouncement continues to require lessees to distinguish between operating and financing, formerly known as capital leases, and lessors to distinguish between sales-type, direct financing, and operating leases for income statement purposes. This accounting update is effective for annual periods, and for interim periods within those annual periods, beginning after December 15, 2018. Early adoption is permitted, and entities are required to recognize and measure leases at the beginning of the earliest period presented using a modified retrospective approach with certain optional practical expedients. We are currently evaluating the impact that this pronouncement will have on our consolidated financial statements.

18. SUBSEQUENT EVENTS

Distribution to Partners

On July 28, 2016, the board of directors of Enbridge Management declared a distribution payable to our partners on August 12, 2016. The distribution will be paid to unitholders of record as of August 5, 2016 of our available cash of $262.5 million at June 30, 2016, or $0.5830 per limited partner unit. Of this distribution, $216.1 million will be paid in cash, $45.5 million will be distributed in i-units to our i-unitholder, Enbridge Management, and due to the i-unit distribution, $0.9 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.

18. SUBSEQUENT EVENTS – (continued)

Distribution to Series EA Interests

On July 28, 2016, 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 $63.0 million to the noncontrolling interest in the Series EA, while $21.0 million will be paid to us.

Distribution to Series ME Interests

On July 28, 2016, 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 $39.4 million to the noncontrolling interest in the Series ME, while $13.1 million will be paid to us.

Distribution from MEP

On July 27, 2016, the board of directors of Midcoast Holdings, L.L.C., the general partner of MEP, declared a cash distribution payable to their partners on August 12, 2016. The distribution will be paid to unitholders of record as of August 5, 2016, of MEP's available cash of $16.5 million at June 30, 2016, or $0.3575 per limited partner unit. MEP will pay $7.6 million to their public Class A common unitholders, while $8.9 million in the aggregate will be paid to us with respect to our Class A common units, our subordinated units, and to Midcoast Holdings, L.L.C. with respect to its general partner interest.

Midcoast Operating Distribution

On July 27, 2016, the general partner of Midcoast Operating declared a cash distribution by Midcoast Operating payable on August 12, 2016 to its partners of record as of August 5, 2016. Midcoast Operating will pay $19.2 million to us and $25.3 million to MEP.

During any quarter until the quarter ending December 31, 2017, if MEP's quarterly declared distribution exceeds its distributable cash, as that term is defined in Midcoast Operating's limited partnership agreement, we receive a decreased quarterly distribution from Midcoast Operating, and MEP receives a corresponding increase to its quarterly distribution in the amount that MEP's declared distribution exceeds its distributable cash. Midcoast Operating's adjustment of our distribution will be limited by our pro rata share of the Midcoast Operating quarterly cash distribution and a maximum of $0.005 per unit quarterly distribution increase by MEP. There is no requirement for MEP to compensate us for these adjusted distributions, except for settling our capital accounts with Midcoast Operating in a liquidation scenario. For the three and six months ended June 30, 2016, our quarterly distribution from Midcoast Operating was reduced by $2.3 million and $3.1 million, respectively.

EUS 364-day Credit Facility

On July 26, 2016, we entered into an unsecured revolving 364-day credit agreement, which we refer to as the EUS 364-day Credit Facility, with Enbridge (U.S.) Inc., or 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, (1) on a revolving basis for a 364-day period and (2) 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 based, at our election, 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.

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 (1) debt or equity securities in a registered public offering, or (2) limited partnership interests in Midcoast Operating to MEP.

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, 2015, as filed with the Securities and Exchange Commission, or the SEC, on February 17, 2016.

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 Federal Energy Regulatory Commission, or 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, NGLs and condensate prices. In addition, we also provide marketing services of natural gas and NGLs to wholesale customers. 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.

The following table reflects our operating income by business segment and corporate charges for the three and six months ended June 30, 2016 and 2015.

	For the three months ended June 30,		For the six months ended June 30,	
	2016	2015	2016	2015
	(in millions)			
Operating income (loss)				
Liquids	$ 324.5	$ 271.6	$ 625.9	$ 541.8
Natural Gas	(60.1)	(277.6)	(90.0)	(304.2)
Corporate, operating and administrative	(2.7)	(3.6)	(6.2)	(7.6)
Total operating income (loss)	261.7	(9.6)	529.7	230.0
Interest expense	(101.5)	(78.0)	(214.4)	(126.3)
Allowance for equity used during construction	13.3	17.3	25.6	40.3
Other income	6.7	6.0	14.2	11.9
Income (loss) before income tax (expense) benefit	180.2	(64.3)	355.1	155.9
Income tax (expense) benefit	(2.5)	3.8	(5.0)	1.4
Net income (loss)	177.7	(60.5)	350.1	157.3
Less: Net income attributable to:				
Noncontrolling interest	70.3	10.0	139.1	61.3
Series 1 preferred unit distributions	22.5	22.5	45.0	45.0
Accretion of discount on Series 1 preferred units	1.2	4.1	2.3	8.0
Net income (loss) attributable to general and limited partner ownership interests in Enbridge Energy Partners, L.P.	$ 83.7	$ (97.1)	$ 163.7	$ 43.0

Highlights

Liquids

Our Liquids segment operating income increased $52.9 million and $84.1 million for the three and six months ended June 30, 2016, respectively, as compared to the same periods in 2015 primarily due to additional assets placed in service and an increase in volumes on our systems. In 2015, $1.6 billion of additional assets were placed into service on our Lakehead system, including portions of the Eastern Access, Mainline Expansion projects, and other projects. Average daily volumes delivered on our liquids systems increased 243,000 and 340,000 Bpd, for the three and six months ended June 30, 2016, respectively, when compared to the same periods in 2015 due mostly to increased capacity from the expansions mentioned above. The increase in operating income was partially offset by increases in property taxes and depreciation expense for the three and six months ended June 30, 2016.

Natural Gas

Our Natural Gas segment operating loss decreased $217.5 million and $214.2 million for the three and six months ended June 30, 2016, respectively, as compared to the same periods in 2015, primarily due to decreases in goodwill impairment losses. During the three and six months ended June 30, 2015, our Natural Gas segment recognized a $246.7 million goodwill impairment charge. No similar goodwill impairment charge was recognized in the same periods of 2016. The decrease in segment operating loss was offset by reduced segment gross margin as a result of the commodity price environment for natural gas, NGLs, condensate and crude oil which continues to impact production volumes. The average daily volumes of our major systems decreased by approximately 265,000 and 286,000 MMBtu/d for the three and six months ended June 30, 2016, respectively.

Derivative Transactions and Hedging Activities

Contractual arrangements in our Liquids, Natural Gas, and Corporate segments expose us to market risks associated with changes in (1) 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 (2) 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'' and ''Power''
- Natural Gas segment commodity-based derivatives — ''Commodity sales'' and ''Commodity costs''
- Corporate 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 June 30,		For the six months ended June 30,	
	2016	2015	2016	2015
	(in millions)			
Liquids segment:				
Non-qualified hedges	$ (5.1)	$ (8.3)	$ (6.8)	$(12.2)
Natural Gas segment:				
Hedge ineffectiveness	—	—	—	(4.0)
Non-qualified hedges	(45.8)	(24.6)	(72.9)	(55.7)
Commodity derivative fair value net losses	(50.9)	(32.9)	(79.7)	(71.9)
Corporate:				
Interest rate hedge ineffectiveness	(1.5)	3.7	(3.4)	32.4
Derivative fair value net losses	$(52.4)	$(29.2)	$(83.1)	$(39.5)

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 June 30,		For the six months ended June 30,	
	2016	2015	2016	2015
	(in millions)			
Operating Results:				
Operating revenue	$621.3	$533.0	$1,251.0	$1,088.1
Operating expenses:				
Environmental costs, net of recoveries	0.1	(0.8)	17.0	—
Operating and administrative	132.1	116.3	268.9	246.7
Power	59.7	57.2	132.5	120.8
Asset impairment	—	—	0.4	—
Depreciation and amortization	104.9	88.7	206.3	178.8
Total operating expenses	296.8	261.4	625.1	546.3
Operating income	$324.5	$271.6	$ 625.9	$ 541.8
Operating Statistics				
Lakehead system:				
United States[(1)]	1,887	1,803	1,980	1,851
Canada[(1)]	553	405	608	418
Total Lakehead system delivery volumes[(1)]	2,440	2,208	2,588	2,269
Barrel miles (billions)	168	150	359	307
Average haul (miles)	759	746	761	748
Mid-Continent system delivery volumes[(1)]	216	221	192	210
North Dakota system:				
Trunkline[(1)]	381	362	392	351
Gathering[(1)]	—	3	—	2
Total North Dakota system delivery volumes[(1)]	381	365	392	353
Total Liquids segment delivery volumes[(1)]	3,037	2,794	3,172	2,832

(1) Average barrels per day in thousands.

Three months ended June 30, 2016, compared with the three months ended June 30, 2015

Operating income of our Liquids segment for the three months ended June 30, 2016, increased $52.9 million, as compared with the same period in 2015. Operating revenue on the Lakehead system increased $116.9 million for the three months ended June 30, 2016, as compared with the same period in 2015. Operating revenues on the Mid-Continent and North Dakota systems for the three months ended June 30, 2016 were relatively flat, when compared to the same period in 2015.

Operating revenue on our Lakehead system increased $77.3 million from increased surcharge revenue for projects subject to regulatory accounting, primarily as a result of placing $1.6 billion of additional assets into service on the Lakehead system in 2015. These additional assets placed into service included components of the Eastern Access, Mainline Expansion, and other expansion projects. These amounts were partially offset by an $8.6 million decrease in rates due to greater qualifying volume credits related to Lakehead toll revenues.

The Lakehead system experienced a period over period increase of 232,000 Bpd in average daily delivery volumes, which resulted in a $39.1 million increase in operating revenues period over period. Increased volumes on the Lakehead system were a result of additional system capacity from the aforementioned assets that were placed into service and increased downstream demand from the completion of certain Enbridge Light Oil Market Access Program projects that expanded access to markets in the Midwest and Eastern Canada for growing volumes of light oil production.

The increase in operating income on the Lakehead system was offset by an approximate $20 million decrease due to the impact of extreme wildfires in northeastern Alberta during the three months ended June 30, 2016, as compared to the same period in 2015. The impact of the wildfires during the first week of May 2016 in northeastern Alberta hindered throughput in the second quarter of 2016 as certain upstream facilities were temporarily shut down resulting in disruption of service on the Lakehead System. The reduced system deliveries decreased operating revenue by approximately $29 million and power costs by approximately $9 million for the three months ended June 30, 2016. Oil sands production substantially came back online by the end of June 2016, and throughput on the Lakehead system and overall system utilization are expected to return to levels anticipated at the outset of the year, during the third quarter of 2016.

The North Dakota system experienced an increase of 16,000 Bpd in average daily delivery volumes, which resulted in an increase of $2.6 million in operating revenues. Increased volumes on the North Dakota system were also a result of increased downstream demand from the completion of certain Enbridge Light Oil Market Access Program projects and by volumes shifting from other higher cost alternatives such as transportation by rail.

The operating and administrative expenses of our Liquids segment increased $15.8 million for the three months ended June 30, 2016, when compared with the same period in 2015, primarily due to cost increases of $17.3 million of property taxes. The increase in property taxes is primarily a result of additional assets placed into service as discussed above.

The increase in depreciation expense of $16.2 million for the three months ended June 30, 2016, when compared to the same period in 2015 is directly attributable to additional assets placed into service, primarily on the projects discussed above.

Six months ended June 30, 2016, compared with the six months ended June 30, 2015

Operating income of our Liquids segment for the six months ended June 30, 2016, increased $84.1 million, as compared with the same period in 2015. Operating revenue on the Lakehead system increased $203.7 million for the six months ended June 30, 2016, as compared with the same period in 2015. Operating revenue on the North Dakota system decreased $13.6 million for the six months ended June 30, 2016, as compared with the same period in 2015. Operating revenue on the Mid-Continent system for the six months ended June 30, 2016 was relatively flat, when compared to the same period in 2015.

Operating revenue on the Lakehead system increased $149.9 million from increased surcharge revenue for projects subject to regulatory accounting, primarily as a result of placing $1.6 billion of additional assets into service on the Lakehead system in 2015. These additional assets placed into service included components of the Eastern Access, Mainline Expansion, and other expansion projects. These amounts were partially offset by a $53.6 million decrease in rates due to greater qualifying volume credits related to Lakehead toll revenues.

The Lakehead system experienced a period over period increase of 319,000 Bpd in average daily delivery volumes, which resulted in an $80.7 million increase in operating revenues period over period. Increased volumes on the Lakehead system were a result of additional system capacity from the assets that were placed into service, as mentioned above, and increased downstream demand from the completion of certain Enbridge Light Oil Market Access Program projects that expanded access to markets in the Midwest and Eastern Canada for growing volumes of light oil production. In addition, operating revenue on the Lakehead system increased $17.5 million due to higher average rates, when compared to the same period in 2015.

The increase in operating income on our Lakehead system was offset by an approximate $20 million decrease due to the impact of extreme wildfires in northeastern Alberta, as discussed above, during the six months ended June 30, 2016, as compared to the same period in 2015. The reduced system deliveries decreased operating revenue by approximately $29 million and power costs by approximately $9 million for the six months ended June 30, 2016.

The North Dakota system experienced an increase of 39,000 Bpd in average daily delivery volumes, which resulted in an increase of $5.8 million in operating revenues. Increased volumes on the North Dakota system were also a result of increased downstream demand from the completion of certain Enbridge Light Oil Market Access Program projects and by volumes shifting from other higher cost alternatives such as transportation by rail. These increases were partially offset by a decrease of $10.2 million in operating revenue due to lower average rates on the North Dakota system as certain surcharge rates subject to an annual adjustment were decreased effective April 1, 2015 and 2016, as well as lower rail revenues of $10.7 million related to the Berthold rail facility.

Environmental costs, net of recoveries, increased $17.0 million for the six months ended June 30, 2016, when compared with the same period in 2015. This increase is primarily related to a $15.0 million increased cost accrual for estimated fines and penalties associated with the Line 6B crude oil release.

The increase of $22.2 million in operating and administrative expenses period over period was also due to cost increases of $23.2 million of property taxes. These cost increases primarily resulted from the additional assets placed into service as discussed above.

Power costs increased $20.4 million for the six months ended June 30, 2016, when compared to the same period in 2015, primarily as a result of an increase in volumes on our systems.

The increase in depreciation expense of $27.5 million for the six months ended June 30, 2016, when compared to the same period in 2015, is directly attributable to additional assets placed into service.

Future Prospects Update for Liquids

We currently have a multi-billion dollar growth program underway, with projects coming into service through early 2019, in addition to options to increase our economic interest in projects that are jointly funded by us and Enbridge. Furthermore, Enbridge has a large inventory of United States liquid pipeline assets and has previously indicated that it would from time to time consider selective drop-down opportunities to us. However, in light of current market conditions, and their effect on our financing capacity, it is unlikely that any such drop-down transactions will be pursued in the near term.

Impact of Commodity Price Declines

Volatility in commodity prices can impact production volumes in the oil sands region of Western Canada and the Bakken region of North Dakota, our two primary crude oil supply basins.

The relatively high costs and large up-front capital investments required by oil sands projects involve significant assumptions around short-term and long-term crude oil fundamentals, including world supply and demand, North American supply and demand, and price outlook, among many other factors. As oil sands production is long-term in nature, the long-term outlook is significant to a producer's investment decision. In the near-term, the current pricing environment is not expected to impact projected growth from the oil sands region.

We expect that the current crude oil price downturn may result in deferral of some oil sands projects, particularly if the current pricing environment continues throughout 2016. However, we expect that projects already under construction will be finished and enter production. In addition, current production volumes from the oil sands are unlikely to decrease absent an operational upset at any of the oil sands operations. Accordingly, we do not anticipate significant changes in our short-term crude oil volume outlook. Our long-term growth in volumes and additional infrastructure expansion will depend on long-term fundamentals. During this period of uncertainty, we believe our pipeline systems are positioned to capture incremental pipeline capacity needs with lower cost, smaller scale expansions of our large Lakehead, North Dakota and Mid-Continent pipeline systems.

Tight sands oil production in any basin in North America will be comparatively more sensitive to the short-term changes in commodity prices due to the production profile associated with tight sands oil wells. Accordingly, we expect a reduction in the growth rate for North American tight sands and shale oil. We believe that rail will be the source of transportation most directly impacted by any declines in production due to its comparatively higher cost relative to pipeline transportation.

Financial impacts to our pipeline systems, in the event the rate of growth were to slow or volumes were to decline, is muted by our cost-of-service agreements, toll structures and demand to transport crude oil from existing production. We do not believe that the decline in crude oil prices will impact our liquids segment meaningfully in the short-term. However, a long-term decline in crude oil prices could have a more significant impact on future production and our rate of growth.

Expansion Projects

The table and discussion below summarize our commercially secured projects for the Liquids segment, which have been recently placed into service or 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	Early 2019	EEP[(2)]
Sandpiper Project[(1)]	2,600	Early 2019	Joint[(3)]
Eastern Access Projects:			
Line 6B Expansion	320	Complete	Joint[(4)]
U.S. Mainline Expansions:			
Line 61 (Additional tankage)	380	Third quarter 2016	Joint[(5)]
Line 61 (1,200,000 Bpd capacity)[(6)]	435	Early 2019	Joint[(5)]

(1) Estimated in-service dates and capital costs are pending regulatory and other approvals.

(2) A special committee of independent directors of the Board of Enbridge Management has been established to consider a joint funding agreement with Enbridge.

(3) Jointly funded 62.5% by us and 37.5% by Williston, an affiliate of MPC, under the North Dakota Pipeline Company Amended and Restated Limited Liability Company Agreement. Estimated capital costs are presented at 100% before Williston's contributions.

(4) Jointly funded 25% by us and 75% by our General Partner under the Eastern Access Joint Funding agreement. Estimated capital costs are presented at 100% before our General Partner's contributions.

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

(6) Estimated in-service date will be adjusted to coincide with the in-service date of the Sandpiper Project and the impact of cost to be reviewed.

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 Line 3 Replacement Program, referred to as the US L3R Program, includes replacing 358 miles from the U.S./Canadian border at Neche, North Dakota to Superior, Wisconsin. While the L3R Program will not provide an increase in the overall capacity of the mainline system, it will support the safety and operational reliability of the system, enhance flexibility and allow us and Enbridge to optimize throughput on the mainline system from Western Canada into Superior, Wisconsin.

We are in the process of obtaining the appropriate permits for constructing the US 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 Minnesota Public Utilities Commission, or MNPUC. The MNPUC found both the Certificate and Route Permit applications for the US L3R Program through Minnesota to be complete. The MNPUC had sent the Certificate application to the Administrative Law Judge, or ALJ, for a pre-hearing meeting to establish a schedule. With respect to the Route Permit, the Minnesota Department of Commerce held public scoping meetings in August 2015. As a result of the Minnesota Court of Appeals decision for the Sandpiper Project, as discussed below, the ALJ requested direction on how to proceed with the Certificate process for Line 3. On February 1, 2016, the MNPUC issued a written order, or the US L3R Order, joining the Line 3 Certificate and Route Permit dockets and requiring the Department of Commerce, or DOC, to prepare an Environmental Impact Statement, or EIS, before the Certificate and Route Permit processes commence, and sent the cases to the Office of Administrative Hearings, or OAH, with direction to restart the process. On February 5, 2016, we filed a Petition for Reconsideration of the requirement to provide an EIS ahead of the commencement of the Certificate and Route Permit proceedings noted in the US L3R Order. At a hearing held on March 24, 2016 the MNPUC denied the Petition for Reconsideration.

With the issuance of the Environmental Assessment Worksheet, or EAW, on April 11, 2016 the MNPUC has commenced the EIS process. Consultation regarding the EAW, which defines the scope of the EIS, commenced with a series of public meetings in communities in Minnesota on April 25, 2016, which concluded on May 13, 2016. The DOC is addressing the comments received on the draft EIS scope and last reported that it would issue its scoping recommendations to the MNPUC in July 2016. Since then, no scoping recommendation has been issued. We now expect it to be issued in August 2016.

The ALJ, who is overseeing the Line 3 Certificate and Route Permit processes held a scheduling conference on May 16, 2016 at which the timeline for the scoping recommendation was discussed. A second pre-hearing conference has been scheduled for August 10, 2016 to further discuss the regulatory schedule. Subject to regulatory and other approvals, the US L3R Program is expected to be completed in early 2019. We continue to review the impact of the US L3R Order on the US L3R Program's schedule and cost estimates.

A special committee of independent directors of the board of Enbridge Management has been established to consider a proposal from our General Partner, on behalf of Enbridge, that would establish joint funding arrangements for the US L3R Program by creating an additional jointly owned series of partnership interests in Enbridge Energy, Limited Partnership, or OLP, similar to the series established for Eastern Access and Mainline Expansion.

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.

Light Oil Market Access Program

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 Light Oil Market Access Program includes several projects that will provide increased pipeline capacity on our North Dakota regional system, further expand capacity on our U.S. mainline system, upsize the Eastern Access Projects, enhance Enbridge's Canadian mainline terminal capacity and provide additional access to U.S. Midwestern refineries.

Sandpiper Project

Included in the Light Oil Market Access Program is the Sandpiper Project, which will expand and extend the North Dakota feeder system by 225,000 Bpd to a total of 580,000 Bpd. The proposed expansion will involve construction of an approximate 600-mile pipeline from Beaver Lodge Station near Tioga, North Dakota to the Superior, Wisconsin mainline system terminal. The new line will twin the existing 210,000 Bpd North Dakota system mainline, which now terminates at Clearbrook Terminal in Minnesota, adding 250,000 Bpd of capacity on the twin line between Tioga and Berthold, North Dakota and 225,000 Bpd of capacity on the twin line between Berthold and Clearbrook both with new 24-inch diameter pipelines, in addition to adding 375,000 Bpd between Clearbrook and Superior with a 30-inch diameter pipeline.

We are in the process of obtaining the appropriate permits for the construction of the Sandpiper Project in Minnesota. The project requires both a Certificate and Route Permit from the MNPUC. Sandpiper and US L3R Program are being processed independently by the MNPUC; however, because the two projects follow the same route in eastern Minnesota, the MNPUC has required that the agencies prepare the environmental assessment jointly for the two projects before publishing a separate EIS for each project. On August 3, 2015, the MNPUC issued an order granting a Certificate and a separate order restarting the Route Permit proceedings. On September 14, 2015, the Minnesota Court of Appeals reversed the MNPUC's Certificate order stating that an EIS must be prepared prior to reaching a final decision in cases where proceedings have been separated and handled sequentially. On January 11, 2016, the MNPUC issued a written order, or the Sandpiper Order, rejoining the Certificate and Route Permit process, requiring the DOC to commence preparation of an EIS, ordering the OAH to recommence processing the Certificate and Route Permit applications but to take judicial notice of the record already developed for the Certificate, and requiring that a final EIS be issued before the Certificate and Route Permit processes commence. As discussed above, on February 1, 2016, we filed a Petition for Reconsideration for the requirement to provide an EIS ahead of the commencement of the Certificate and Route Permit noted in the Sandpiper Order. At a hearing held on March 24, 2016 the MNPUC denied the Petition for Reconsideration.

With the issuance of the EAW on April 11, 2016 the MNPUC has commenced the EIS process. Consultation regarding the EAW, which defines the scope of the EIS, commenced with a series of public meetings in communities in Minnesota on April 25, 2016, which concluded on May 13, 2016. The DOC is addressing the comments received on the draft EIS scope and last reported that it would issue its scoping recommendations to the MNPUC in July 2016. Since then, no scoping recommendation has been issued. We now expect it to be issued in August 2016.

The ALJ overseeing the Sandpiper Certificate of Need and Route Permit processes held a scheduling conference in June 2016 at which the DOC provided a draft EIS schedule. A second meeting will be held on August 10, 2016 to further discuss the regulatory schedule. Subject to regulatory and other approvals, Sandpiper is expected to be completed in early 2019. We continue to review the impact of the Sandpiper Order on the project's schedule and cost estimates.

Marathon Petroleum Corporation, or MPC, has been secured as an anchor shipper for the Sandpiper project. As part of the arrangement, we, through our subsidiary, NDPC, and Williston Basin Pipeline LLC, or Williston, an affiliate of MPC, entered into an agreement to, among other things, admit Williston as a member of NDPC. Williston will fund 37.5% of the Sandpiper Project construction and have the option to participate in other growth projects within NDPC, unless specifically excluded by the agreement; this investment is not to exceed $1.2 billion in aggregate. In return for funding part of Sandpiper's construction, Williston will obtain an approximate 27% equity interest in NDPC at the in-service date of Sandpiper.

Eastern Access Projects

The Eastern Access Projects included a series of crude oil pipeline expansion projects providing increased access to refineries in the U.S. Upper Midwest and the Canadian provinces of Ontario and Quebec for light crude oil produced in western Canada and the United States. The majority of the Eastern Access Projects were completed between 2013 and 2015. The remaining project was an expansion project for Line 6B to increase capacity from 500,000 Bpd to 570,000 Bpd and included: pump station modifications at Griffith, Niles and Mendon; additional modifications at the Griffith and Stockbridge terminals; and breakout tankage at Stockbridge. The expansion was placed into service in June 2016 at an approximate cost of $320 million.

We will operate the Eastern Access Projects on a cost-of-service basis. The Eastern Access Projects were funded 75% by our General Partner and 25% by us under the Eastern Access Joint Funding Agreement. Within one year of the in-service date, we will have the option to increase our economic interest by up to 15% at cost. On July 30, 2015, we reached an agreement with the General Partner in which the General Partner agreed to temporarily forego its Series EA cash distributions through the quarter ended March 31, 2016. The General Partner's capital funding contribution requirements to the Eastern Access projects were netted against its foregone cash distributions. For further details, see *Amendment of OLP Limited Partnership Agreement* under Item 1. *Financial Statements*, Note 10. *Related Party Transactions*.

U.S. Mainline Expansion

The U.S. Mainline Expansion Projects includes 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. The timing of the receipt of the amendment to the Presidential border crossing permit to allow for increased flow on the Line 67 pipeline across the border cannot be determined at this time. A number of temporary system optimization actions have been undertaken to substantially mitigate any impact on throughput associated with any delays in obtaining this amendment.

The remaining scope of the Line 61 expansion, between Superior, Wisconsin and Flanagan, Illinois requires only the addition of pumping horsepower with no pipeline construction. The remaining work includes additional tankage which is expected to cost approximately $380 million with various completion dates continuing through the third quarter of 2016. The remaining work also 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 US L3R Program and Sandpiper Project.

We will 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 Agreement, which parallels the Eastern Access Joint Funding Agreement. We have the option to increase our economic interest held up to 15% at cost. On July 30, 2015, we reached an agreement with the General Partner in which the General Partner agreed to temporarily forego its Series EA cash distributions through the quarter ended March 31, 2016. The General Partner's capital funding contribution requirements to the Eastern Access projects were netted against its foregone cash distributions. For further details, see *Amendment of OLP Limited Partnership Agreement* under Item 1. *Financial Statements*, Note 10. *Related Party Transactions*.

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 June 30,		For the six months ended June 30,	
	2016	2015	2016	2015
	(in millions)			
Operating revenues	$ 427.6	$ 780.1	$ 859.5	$ 1,653.6
Commodity costs	359.1	670.6	707.1	1,449.7
Segment gross margin	68.5	109.5	152.4	203.9
Operating and administrative	78.0	87.3	152.3	170.0
Goodwill impairment	—	246.7	—	246.7
Asset impairment	10.6	12.3	10.6	12.3
Depreciation and amortization	40.0	40.8	79.5	79.1
Operating expenses	128.6	387.1	242.4	508.1
Operating loss	(60.1)	(277.6)	(90.0)	(304.2)
Other income	6.6	5.9	13.7	11.6
Net loss	$ (53.5)	$ (271.7)	$ (76.3)	$ (292.6)
Operating Statistics (MMBtu/d)				
East Texas	931,000	968,000	939,000	988,000
Anadarko	637,000	794,000	645,000	811,000
North Texas	203,000	274,000	210,000	281,000
Total	1,771,000	2,036,000	1,794,000	2,080,000
NGL Production (Bpd)	71,747	81,056	72,666	81,051

Three months ended June 30, 2016, compared with the three months ended June 30, 2015

The operating loss of our Natural Gas segment for the three months ended June 30, 2016, decreased $217.5 million as compared with the same period in 2015, primarily as a result of a reduction in goodwill impairment charge. During the three months ended June 30, 2015, the Natural Gas segment recognized a goodwill impairment charge of $246.7 million. No similar charge was recorded during the same period in 2016. Operating loss was further decreased by $1.7 million for the three months ended June 30, 2016, as compared to the same period in 2015, as the impairment loss on certain trucking assets of $10.6 million for the three months ended June 30, 2016 was smaller than the impairment loss on our Tinsley system of $12.3 million during the same period in 2015. Decreases in ''Operating revenues'' and ''Commodity costs'' for the three months ended June 30, 2016, as compared with the same period in 2015, are primarily due to decreases in commodity prices and the resulting decrease in volumes from reduced drilling activities.

Segment gross margin decreased by $41.0 million, in part due to a net increase in non-cash, mark-to-market losses of $21.2 million for the three months ended June 30, 2016, as compared with the same period in 2015. These losses are primarily related to the increased commodity prices of NGLs period over period, partially offset by the gains from the reversal of previously recognized unrealized market-to-market losses as the underlying transactions were settled.

Segment gross margin decreased by approximately $9.3 million for the three months ended June 30, 2016, as compared to the same period in 2015, due to reduced natural gas production volumes. The average daily volumes of our major systems for the three months ended June 30, 2016, decreased by 265,000 MMBtu/d, or 13%, when compared to the same period in 2015. The average NGL production for the three months ended June 30, 2016, decreased by 9,309 Bpd, or 11%, when compared to the same period in 2015. 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 from producers in the areas we operate.

Segment gross margin decreased $4.5 million for the three months ended June 30, 2016, compared with the same period in 2015 due to a decline 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.

Segment gross margin decreased $4.4 million for the three months ended June 30, 2016, when compared to the same period in 2015, due to a decrease in processing margins primarily driven by lower commodity prices along with decline in NGL volumes and associated keep whole volumes in the Anadarko region.

Operating and administrative costs decreased $9.3 million for the three months ended June 30, 2016, compared to the same period in 2015, primarily due to workforce reductions and other cost reduction efforts.

Six months ended June 30, 2016, compared with the six months ended June 30, 2015

The operating loss of our Natural Gas segment for the six months ended June 30, 2016, decreased $214.2 million, as compared with the same period in 2015, due to reductions in goodwill and asset impairments, as discussed above. Decreases in "Operating revenues" and "Commodity costs" for the six months ended June 30, 2016, as compared with the same period in 2015, are due to the reasons discussed above.

Segment gross margin decreased $51.5 million for the six months ended June 30, 2016, as compared with the same period in 2015, primarily due to $19.1 million from decreased production volumes. The average daily volumes of our major systems decreased by approximately 286,000 MMBtu/d, or 14%, for the six months ended June 30, 2016, when compared to the same period in 2015. The average NGL production for the six months ended June 30, 2016, decreased 8,385 Bpd, or 10%, when compared to the same period in 2015. 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.

Segment gross margin also decreased by $13.2 million due to increased non-cash, mark-to-market losses for the six months ended June 30, 2016, as compared to the same period in 2015. This change primarily related to losses due to the increased commodity prices of NGLs period over period, partially offset by the gains from the reversal of previously recognized unrealized mark-to-market losses as the underlying transactions were settled.

Our segment gross margin also decreased $10.4 million due to decreased margins from lower commodity prices, net of hedges, related to contracts where we were paid in commodities for our services. Commensurate with the overall decline in commodity prices since 2015, the forecasted 2016 commodity-based cash flows are currently hedged at lower weighted-average hedge prices relative to those realized in 2015.

Segment gross margin also decreased due to reduced activity of $9.6 million. In the third quarter of 2015, we sold our non-core Tinsley system and assigned certain storage agreements, transportation contracts and other arrangements to third parties. As a result, $9.6 million of segment margin generated by these assets for the six months ended June 30, 2015 was not present in the same period of 2016.

Segment gross margin decreased $6.5 million for the six months ended June 30, 2016, when compared to the same period in 2015, due to a decrease in processing margins primarily driven by lower commodity prices along with decline in NGL volumes and associated keep whole volumes in the Anadarko and East Texas regions.

Operating and administrative costs decreased $17.7 million for the six months ended June 30, 2016, compared to the same period in 2015, primarily due to workforce reductions and other cost reduction efforts. Operating and administrative costs also decreased due to gains of $5.6 million recorded to recognize return of escrow funds and a reversal of a contingent liability related to an acquisition. For further details regarding these amounts, refer to Item 1. *Financial Statements*, Note 3. *Acquisitions*.

Future Prospects 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 commodity price environment, we expect drilling activity to remain low and as a result, we expect to see continued low volumes on our systems in 2016, and potentially beyond.

We have largely mitigated our near-term direct commodity price risk through our hedging program. We have hedged over 90% and approximately 60% of our direct forecasted commodity cash flow exposure for 2016 and 2017, respectively. 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, we have partially mitigated the impact on our results from lower volumes through cost reductions to our business, including workforce reductions.

We have sought to expand our natural gas gathering and processing services by: (1) capturing opportunities within our footprint, (2) expanding outside of our existing footprint through strategic acquisitions, (3) providing an array of services for both natural gas and NGLs in combination with core asset optimization, and (4) capitalizing on new market opportunities by diversifying geographically and by commodity composition. However, in light of the low commodity price environment, we are evaluating opportunities to strengthen our natural gas business. As part of this evaluation, in addition to, or as alternatives to, possible expansion strategies for our natural gas gathering and processing services discussed above, we are exploring strategic alternatives for our investments in each of Midcoast Operating and MEP. We have begun working with MEP to explore and evaluate a broad range of strategic alternatives to address these challenges within our Natural Gas business. These additional various strategic alternatives may include, but are not necessarily limited to: asset sales; mergers, joint ventures, reorganizations or recapitalizations; and further reductions in operating and capital expenditures for the Natural Gas business. The evaluation process is ongoing, and no decision on any particular strategic alternative has been reached. We expect to complete the evaluation by the end of this year.

Expansion Projects

Eaglebine Developments

The Eaglebine is an oil play in East Texas that spans over five counties and is comprised of multiple formations, including but not limited to, the Woodbine, Buda, Glenrose and Eagle Ford formations. We completed several construction projects in this play, including the construction of the Ghost Chili pipeline project, which consists of a lateral and associated facilities that create gathering capacity of over 50 MMcf/d for rich natural gas to be delivered from Eaglebine production areas to our complex of cryogenic processing facilities in East Texas. The initial facilities were placed into service in October 2015. We continue to assess the need to construct the Ghost Chili Extension Lateral to fully utilize this gathering capacity with the rest of our processing assets when additional development in the basin supports it. Given the proximity of our existing East Texas assets, this expansion into Eaglebine will allow us to offer gathering and processing services while leveraging assets on our existing footprint.

Any future funding is to be provided by us and MEP based on our proportionate ownership percentages in Midcoast Operating, subject to market conditions and our financing capacity.

Corporate

Our corporate results consist of interest expense, allowance for equity used during construction, noncontrolling interest and other costs such as income taxes, which are not allocated to the business segments.

	For the three months ended June 30,		For the six months ended June 30,	
	2016	2015	2016	2015
	(in millions)			
Operating Results:				
Operating and administrative expenses	$ 2.7	$ 3.6	$ 6.2	$ 7.6
Operating loss	(2.7)	(3.6)	(6.2)	(7.6)
Interest expense, net	(101.5)	(78.0)	(214.4)	(126.3)
Allowance for equity used during construction	13.3	17.3	25.6	40.3
Other income	0.1	0.1	0.5	0.3
Loss before income tax (expense) benefit	(90.8)	(64.2)	(194.5)	(93.3)
Income tax (expense) benefit	(2.5)	3.8	(5.0)	1.4
Net loss	$ (93.3)	$(60.4)	$(199.5)	$ (91.9)

Three months ended June 30, 2016, compared with three months ended June 30, 2015

The $32.9 million increase in our segment net loss for the three months ended June 30, 2016, as compared to the same period in 2015, was primarily attributable to an increase in interest expense and income tax expense.

The $23.5 million increase in interest expense was primarily due to an increase in our average outstanding debt balance during the three months ended June 30, 2016, which includes $1.6 billion of senior unsecured notes that were issued in October 2015.

The $6.3 million increase in income tax expense was primarily due to the absence of a one-time tax benefit for the three months ended June 30, 2016, as compared to the same period in 2015. In 2015, we recognized a $5.4 million one-time tax benefit from a reduction in deferred income tax payable during the three months ended June 30, 2015. This reduction was the result of a reduction in the Texas franchise tax rate from the Texas House Bill 32, which was enacted in 2015.

Six months ended June 30, 2016, compared with six months ended June 30, 2015

The $107.6 million increase in our segment net loss for the six months ended June 30, 2016, as compared to the same period in 2015, was primarily attributable to an increase in interest expense of $88.1 million, period over period. The increase is due to an increase in our average outstanding debt balance during the six months ended June 30, 2016, which includes $1.6 billion of senior unsecured notes that were issued in October 2015. In addition, we recognized a $34.4 million decrease to unrealized losses for hedge ineffectiveness that we recognized during the six months ended June 30, 2015. We did not have a similar decrease in the same period of 2016.

Further, allowance for equity used during construction, or AEDC, decreased $14.7 million for the six months ended June 30, 2016, when compared to the same period in 2015, as a result of a 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 discussed above under *Future Prospects for Natural Gas*. 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.

We are evaluating opportunities to strengthen our business in light of the low commodity price environment, which is impacting the performance of our natural gas gathering and processing assets. As part of this process, we are exploring and evaluating strategic alternatives for our investments in each of Midcoast Operating and MEP, as discussed above under *Future Prospects for Natural Gas*, which may include, but are not limited to: asset sales; mergers, joint ventures, reorganizations or recapitalizations; and further reductions in operating and capital expenditures. It may also include selling additional interests in Midcoast Operating to MEP to raise capital over the course of the next several years. Although we are evaluating these opportunities, there is no assurance that any transactions will be pursued or effected.

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.

As of June 30, 2016, although we had a working capital deficit of approximately $0.8 billion, we had approximately $0.9 billion of liquidity to meet our ongoing operational, investing and financing needs as described below.

Available Liquidity

Our primary source of short-term liquidity is provided by our $1.5 billion commercial paper program, which is supported by our $1.975 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 $1.5 billion 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 June 30, 2016, we had approximately $414.1 million in available credit under the terms of our Credit Facilities. For a description of our commercial paper program and our Credit Facilities, refer to Item 1. *Financial Statements*, Note 8. *Debt*.

As set forth in the following table, we had approximately $0.9 billion of consolidated liquidity available to us at June 30, 2016, 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 releases on Line 6B.

	EEP	MEP	Total
		(in millions)	
Cash and cash equivalents	$ 125.0	$ 8.1	$ 133.1
Total commitments under EEP's Credit Facilities	2,600.0	—	2,600.0
Total commitments under MEP's Credit Agreement	—	810.0	810.0
Less: Amounts outstanding under EEP's Credit Facilities	1,740.0	—	1,740.0
Amounts outstanding under MEP's Credit Agreement	—	475.0	475.0
Principal amount of commercial paper outstanding	194.3	—	194.3
Letters of credit outstanding	251.6	—	251.6
Total[(1)]	$ 539.1	$343.1	$ 882.2

(1) On July 26, 2016, we entered into 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. After the addition of this facility, on a pro-forma basis, our total consolidated liquidity is $1.6 billion. For further details, refer to Item 1. *Financial Statements*, Note 18. *Subsequent Events*.

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. If market conditions change and capital markets become 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.

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.

MEP Credit Agreement

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 $810.0 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. The MEP Credit Agreement's current maturity date is September 30, 2018; however, $140.0 million of commitments expire on the original maturity date of November 13, 2016, and an additional $25.0 million of commitments expire on September 30, 2017.

At June 30, 2016, MEP was in compliance with the terms of their financial covenants in the Credit Agreement. 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 2016 without further action on their part. If this were to occur, MEP would seek a waiver from its lenders, seek additional capital contributions, pursue refinancing of the amounts outstanding under the Credit Agreement or seek to take other action to prevent a default under the Credit Agreement, although there is no assurance that MEP could obtain any such necessary 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 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 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.

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. All of the Notes pay interest semi-annually on March 31 and September 30, and commenced on March 31, 2015.

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 S&P 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 June 30, 2016, MEP was in compliance with the terms of their financial covenants under the Notes and the related purchase agreement. 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 2016 without further action on their 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 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.

Joint Funding Arrangements

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

Amendment of OLP Limited Partnership Agreement

On July 30, 2015, the partners amended and restated the limited partnership agreement of the OLP, pursuant to which our General Partner will temporarily forego Series EA and ME, collectively, the Series, distributions commencing in the quarter ended June 30, 2015 through the quarter ended March 31, 2016. The General Partner's capital funding contribution requirements for each of those two Series, commencing in August 2015, will be reduced by the amount of its foregone cash distributions from the respective Series, until the earlier of December 31, 2016 and the date aggregate reductions in capital contributions for such Series are equal to the foregone cash distributions for such Series. To the extent that the General Partner's portion of capital contributions prior to December 31, 2016 are insufficient to cover the General Partner's foregone cash distributions for a Series, beginning with the distribution related to the first quarter of 2017 for that Series, we will receive reduced cash distributions by up to 50%, and the General Partner will receive a comparable increase in cash distributions each quarter until the General Partner has received an aggregate amount of contribution reductions and distribution increases equal to the amount of foregone cash distributions.

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 projects to increase access to refineries in the United States Upper Midwest and in Ontario, Canada for light crude oil produced in western Canada and the United States, which we refer to as the Eastern Access Projects. Except as described above in *Amendment of OLP Limited Partnership Agreement*, these projects are currently jointly funded by our General Partner at 75% and by us at 25%, respectively. Additionally, within one year of the in-service date, we have the option to increase our economic interest by up to 15 percentage points.

Our General Partner made equity contributions totaling $7.2 million and $98.3 million to the OLP for the six months ended June 30, 2016 and 2015, 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 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, which we refer to as our Mainline Expansion Projects. Except as described above in *Amendment of OLP Limited Partnership Agreement*, these projects are currently jointly funded by our General Partner at 75% and us at 25%, under the Mainline Expansion Joint Funding Agreement, which parallels the Eastern Access Joint Funding Agreement. Additionally, within one year of the in-service date, we have the option to increase our economic interest held at that time by up to 15 percentage points.

Our General Partner has made equity contributions totaling $42.8 million and $360.7 million to the OLP for the six months ended June 30, 2016 and 2015, respectively, to fund its equity portion of the construction costs associated with the Mainline Expansion Projects.

Sale of Accounts Receivable

We and certain of our subsidiaries are 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 will purchase 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 are 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.

At June 30, 2016, we sold and derecognized $1,633.5 million of receivables to an indirect, wholly-owned subsidiary of Enbridge, and we received cash proceeds of $1,632.8 million. As of June 30, 2016, $238.8 million of the receivables were outstanding and had not been collected on behalf of the Enbridge subsidiary.

For further details regarding the Receivables Agreement, refer to Item 1. *Financial Statements*, Note. 10. *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 life. 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 $0.5 billion for the six months ended June 30, 2016, including $27.2 million of maintenance capital expenditures. Of those capital expenditures, $63.4 million was financed by contributions from our General Partner and MPC via joint funding arrangements. At June 30, 2016, we had approximately $0.5 billion 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.

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. Due to the completion of major projects, and lower-than-anticipated spending on the Sandpiper and Line 3 Replacement projects in 2016, we expect our expansion capital expenditures to be significantly lower in 2016 than in recent years. The following table sets forth our estimated maintenance and expansion capital expenditures, net of joint funding, of $0.9 billion for the year ending December 31, 2016. We expect to receive funding of approximately $0.3 billion from our General Partner based on our joint funding arrangement for the Eastern Access Projects and Mainline Expansion Projects. Furthermore, we expect to receive funding of approximately $45.0 million from MPC based on our joint funding arrangement for the Sandpiper Project. Although we anticipate making these expenditures in 2016, 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	$ 200
U.S. Mainline Expansions	240
Sandpiper	120
Line 3 Replacement	160
Liquids Integrity Program	265
Expansion Capital	190
Maintenance Capital Expenditures	50
	1,225
Less joint funding from:	
General Partner(2)	330
Third parties	45
Liquids Total	**$ 850**
Natural Gas Projects	
Expansion Capital	$ 40
Maintenance Capital Expenditures	35
	75
Less joint funding from:	
MEP	40
Natural Gas Total	**$ 35**
TOTAL	**$ 885**

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

(2) Joint funding by the General Partner is based on its respective economic interests in the Eastern Access Projects and U.S. Mainline Expansions, and does not take into account the temporary adjustment to contributions and distributions pursuant to the amendment of the OLP limited partnership agreement, as described above.

Environmental

Lakehead Line 6B Crude Oil Release

During the six months ended June 30, 2016, our cash flows were affected by the approximate $12.9 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 our remaining $145.0 million 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 assert that their payment is 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 during the third quarter 2013 and have since amended our lawsuit, such that it now includes only one carrier. While we believe that our claims for the remaining $103.0 million are covered under the policy, there can be no assurance that we will prevail in this lawsuit. Of the remaining $103.0 million coverage limit, $85.0 million is the subject matter of a lawsuit Enbridge filed against one particular insurer and the remaining $18.0 million is awaiting resolution of arbitration, which is not scheduled to occur until the fourth quarter of 2016. While we believe that those costs are eligible for recovery, there can be no assurance we will prevail in the arbitration. For more information regarding cost estimates and fines and penalties, refer to Item 1. *Financial Statements*, Note 11. *Commitments and Contingencies*.

Derivative Activities

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

We record all derivative financial instruments at fair market value in our consolidated statements of financial position. Price assumptions we use to value our non-qualifying derivative financial instruments can affect net income for each period. We use published market price information where available, or quotations from OTC market makers to find executable bids and offers. We may also use these inputs with internally developed methodologies that result in our best estimate of fair value. The valuations also reflect the potential impact of liquidating our position in an orderly manner over a reasonable period of time under present market conditions, including credit risk of our counterparties. The amounts reported in our consolidated financial statements change quarterly as these valuations are revised to reflect actual results, changes in market conditions or other factors, many of which are beyond our control.

The following table provides summarized information about the timing and expected settlement amounts of our outstanding commodity derivative financial instruments based upon the market values at June 30, 2016 for each of the indicated calendar years:

	Notional[(1)]	2016	2017	2018	2019	2020 & Thereafter	Total[(2)]
				(in millions)			
Swaps:							
Natural gas	19,178,817	$ 0.2	$ 1.1	$ —	$ —	—	$ 1.3
NGL	6,211,800	1.2	(2.1)	—	—	—	(0.9)
Crude Oil	2,641,732	1.2	(1.3)	—	—	—	(0.1)
Options:							
Natural gas – puts purchased	828,000	0.6	—	—	—	—	0.6
Natural gas – puts written	828,000	(0.6)	—	—	—	—	(0.6)
Natural gas – calls purchased	828,000	—	—	—	—	—	—
Natural gas – calls written	828,000	—	—	—	—	—	—
NGL – puts purchased	3,132,900	19.2	3.3	—	—	—	22.5
NGL – puts written	119,600	(1.2)	—	—	—	—	(1.2)
NGL – calls purchased	119,600	0.1	—	—	—	—	0.1
NGL – calls written	3,132,900	(0.5)	(4.7)	—	—	—	(5.2)
Crude Oil – puts purchased	1,134,800	10.5	7.8	0.3	—	—	18.6
Crude Oil – calls written	1,134,800	—	(1.7)	(0.8)	—	—	(2.5)
Forward contracts:							
Natural gas	83,530,704	(0.7)	0.2	0.1	0.1	—	(0.3)
NGL	9,008,646	1.2	1.0	—	—	—	2.2
Crude Oil	949,604	(2.1)	—	—	—	—	(2.1)
Totals		$29.1	$ 3.6	$(0.4)	$0.1	$—	$32.4

(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 $0.2 million at June 30, 2016.

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 June 30, 2016 for each of the indicated calendar years:

	Notional	2016	2017	2018	2019	2020	Total[(1)]
				(in millions)			
Interest Rate Derivatives							
Interest Rate Swaps:							
Floating to Fixed	$1,930	$ (2.3)	$ (12.9)	$(11.3)	$(3.0)	$—	$ (29.5)
Pre-issuance hedges	$1,350	(129.8)	(97.9)	(43.7)	—	—	(271.4)
		$(132.1)	$(110.8)	$(55.0)	$(3.0)	$—	$(300.9)

(1) Fair values exclude credit valuation adjustment gains of approximately $4.7 million at June 30, 2016.

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 six months ended June 30, 2016	2015	Variance 2016 vs. 2015 Increase (Decrease)
		(in millions)	
Total cash provided by (used in):			
Operating activities	$ 546.5	$ 646.9	$(100.4)
Investing activities	(660.1)	(996.3)	336.2
Financing activities	98.6	261.3	(162.7)
Net increase decrease in cash and cash equivalents	(15.0)	(88.1)	73.1
Cash and cash equivalents at beginning of year	148.1	197.9	(49.8)
Cash and cash equivalents at end of period	$ 133.1	$ 109.8	$ 23.3

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

	For the six months ended June 30, 2016	2015	Variance 2016 vs. 2015
		(in millions)	
Changes in operating assets and liabilities, net of acquisitions:			
Receivables, trade and other	$ 19.6	$ 45.7	$ (26.1)
Due from General Partner and affiliates	(47.1)	(62.7)	15.6
Accrued receivables	24.7	158.9	(134.2)
Inventory	(14.4)	(1.3)	(13.1)
Current and long-term other assets	(22.6)	(33.0)	10.4
Due to General Partner and affiliates	(27.5)	66.9	(94.4)
Accounts payable and other	(93.6)	(56.6)	(37.0)
Environmental liabilities	(10.0)	(21.6)	11.6
Accrued purchases	(7.7)	(114.8)	107.1
Interest payable	(1.3)	1.2	(2.5)
Property and other taxes payable	(14.7)	(15.6)	0.9
Net change in working capital accounts	$(194.6)	$ (32.9)	$(161.7)

Operating Activities

Net cash provided by our operating activities decreased $100.4 million for the six months ended June 30, 2016, compared to the same period in 2015, primarily due to decreased cash inflows from net changes in operating assets and liabilities and includes:

- Decreased cash from changes in inventory and accrued receivables of $147.3 million primarily resulting from lower commodity prices and volumes;
- Decreased cash from net balances due to and due from the General Partner and its affiliates of $78.8 million resulting from delayed payment on amounts due to the General Partner and its affiliates; and
- Decreased cash from changes in accounts payable and other of $37.0 million, primarily as a result of timing differences in cash payments, which was partially offset by;
- Increased cash from changes in accrued purchases of $107.1 million resulting from lower commodity prices and volumes.

Investing Activities

Net cash used in our investing activities during the six months ended June 30, 2016 decreased by $336.2 million compared to the same period in 2015 primarily due to decreased spending on acquisitions and capital projects.

Financing Activities

Net cash provided by our financing activities decreased $162.7 million for the six months ended June 30, 2016 compared to the same period in 2015 primarily due to the following:

- Decrease in cash provided by contributions from noncontrolling interest of $439.2 million due to a reduction in cash requirements for capital projects and the temporary reductions of contributions from our General Partner on the Series EA and ME interests as discussed above under *Amendment of OLP Limited Partnership Agreement*;
- Decreased net proceeds from our unit issuances of $294.8 million, which occurred in March 2015, while we had no unit issuances in 2016; and
- Increased distributions to our limited partners of $28.2 million.

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

- Decreased repayments of $306.0 million to the General Partner in January 2015, primarily due to the A1 loan in January 2015, while we had no such repayments in 2016;
- Increased cash from net borrowings of $138.3 million; and
- Decreased distributions to noncontrolling interest of $156.0 million due to foregone cash distributions to our General Partner on the Series EA and ME interests as discussed above under *Amendment of OLP Limited Partnership Agreement*.

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 calls into question a FERC policy permitting regulated companies organized as pass-through entities for income tax purposes to include an allowance for income taxes in their rates. The court has remanded the case to the FERC to provide a basis for its decision on income tax allowances for partnership pipelines. At this time, there is not enough information available to us to determine whether the level of income tax allowance included in our regulated rates will change, and if so, by how much.

Lakehead System

Effective April 1, 2016, FERC tariff No. 43.20.0 adjusted rates to update the Facilities Surcharge Mechanism, or FSM. The FSM allows recovery of costs associated with particular shipper-approved projects through an incremental cost-of-service based surcharge that is layered on top of the base index rates. The FSM surcharge reflects our projected costs for these shipper-approved projects for 2016 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 increased our transportation rate for heavy crude oil movements from the Canadian border to the Chicago, Illinois area by approximately $0.17 per barrel, to approximately $2.61 per barrel. The tariff filing also increased our transportation rate for light crude oil movements from the Canadian border to the Chicago, Illinois area by approximately $0.14 per barrel, to approximately $2.16 per barrel. These increases were primarily the result of an adjustment for the difference between estimated and actual costs and throughput for 2015, coupled with an increase in forecasted capital additions for 2016.

On May 31, 2016, we filed FERC tariff No. 43.21.0 with an effective date of July 1, 2016 for our Lakehead system. We decreased rates in compliance with the indexed rate ceilings allowed by the FERC, which incorporates the multiplier of 0.979865 issued by the FERC on May 19, 2016 in Docket No. RM93-11-000.

North Dakota System

Effective April 1, 2016, FERC tariff No. 3.18.0 adjusted rates, including an updated calculation of the Phase 5 Looping and Phase 6 Mainline surcharges. These surcharges are cost-of-service based surcharges that are adjusted each year to actual costs and volumes and are 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 $0.06, to an average of approximately $1.77 per barrel. The Phase 5 Looping surcharge increased primarily due to a decrease in forecasted throughput, and the Phase 6 Mainline surcharge decreased in order to return prior period over recoveries to shippers. Both of these surcharges expire at the end of 2016 and any differences in recoveries will be cash settled with the shippers in 2017.

Effective July 1, 2016, FERC Tariff No. 3.19.0 established new delivery points at Grenora, North Dakota and Little Muddy, North Dakota with rates from Reserve, Montana and Grenora, North Dakota (pump-over) to Grenora, Merchant Storage, North Dakota and from Little Muddy, North Dakota (pump-over) to Little Muddy, Merchant Storage, North Dakota.

Also effective July 1, 2016, FERC Tariff No. 3.20.0 decreased rates in compliance with the indexed rate ceilings allowed by the FERC, which incorporates the multiplier of 0.979865 issued by the FERC on May 19, 2016 in Docket No. RM93-11-000.

Additionally, under the Transportation Services Agreement, or TSA, this tariff adjusted the operating cost charge component of the committed trunkline rates to Berthold, North Dakota to the actual operating costs and throughput volumes for 2015 and the forecasted operating costs and throughput for 2016. Lastly, this tariff discounted the terminal charge for gathering or truck unloading at Little Muddy, ND from the established 2016 ceiling rate of $0.2227 to $0.01 per barrel.

Bakken System

Effective July 1, 2016, FERC Tariff No. 2.3.0 decreased rates in compliance with the indexed rate ceilings allowed by the FERC, which incorporates the multiplier of 0.979865 issued by the FERC on May 19, 2016, in Docket No. RM93-11-000.

Also effective July 1, 2016, FERC tariff No. 3.5.0 adjusted rates in accordance with the TSA that was included in the Petition for Declaratory Order filed on August 26, 2010 in Docket No. OR10-19-000. Additionally, as per the TSA, this tariff adjusted the operating cost charge component of the committed international joint rates to Cromer, Manitoba to the actual operating costs and throughput volumes for 2015 and the forecasted operating costs and throughput for 2016.

Ozark System

Effective December 1, 2015, our Ozark system filed FERC Tariff 48.6.0 to increase its rate from $0.6759 to $0.8403. This filing was made to allow for recovery of costs related to the capital expenditures required to maintain the integrity of the pipeline. As a result of this filing, our Ozark system was not eligible to adjust its rate effective July 1, 2016, in compliance with indexed rate ceilings allowed by the FERC.

SUBSEQUENT EVENTS

Distribution to Partners

On July 28, 2016, the board of directors of Enbridge Management declared a distribution payable to our partners on August 12, 2016. The distribution will be paid to unitholders of record as of August 5, 2016 of our available cash of $262.5 million at June 30, 2016, or $0.5830 per limited partner unit. Of this distribution, $216.1 million will be paid in cash, $45.5 million will be distributed in i-units to our i-unitholder, Enbridge Management, and due to the i-unit distribution, $0.9 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.

Distribution to Series EA Interests

On July 28, 2016, 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 $63.0 million to the noncontrolling interest in the Series EA, while $21.0 million will be paid to us.

Distribution to Series ME Interests

On July 28, 2016, 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 $39.4 million to the noncontrolling interest in the Series ME, while $13.1 million will be paid to us.

Distribution from MEP

On July 27, 2016, the board of directors of Midcoast Holdings, L.L.C., the general partner of MEP, declared a cash distribution payable to their partners on August 12, 2016. The distribution will be paid to unitholders of record as of August 5, 2016, of MEP's available cash of $16.5 million at June 30, 2016, or $0.3575 per limited partner unit. MEP will pay $7.6 million to their public Class A common unitholders, while $8.9 million in the aggregate will be paid to us with respect to our Class A common units, our subordinated units, and to Midcoast Holdings, L.L.C. with respect to its general partner interest.

Midcoast Operating Distribution

On July 27, 2016, the general partner of Midcoast Operating declared a cash distribution by Midcoast Operating payable on August 12, 2016 to its partners of record as of August 5, 2016. Midcoast Operating will pay $19.2 million to us and $25.3 million to MEP.

During any quarter until the quarter ending December 31, 2017, if MEP's quarterly declared distribution exceeds its distributable cash, as that term is defined in Midcoast Operating's limited partnership agreement, we receive a decreased quarterly distribution from Midcoast Operating, and MEP receives a corresponding increase to its quarterly distribution in the amount that MEP's declared distribution exceeds its distributable cash. Midcoast Operating's adjustment of our distribution will be limited by our pro rata share of the Midcoast Operating quarterly cash distribution and a maximum of $0.005 per unit quarterly distribution increase by MEP. There is no requirement for MEP to compensate us for these adjusted distributions, except for settling our capital accounts with Midcoast Operating in a liquidation scenario. For the three and six months ended June 30, 2016, our quarterly distribution from Midcoast Operating was reduced by $2.3 million and $3.1 million, respectively.

EUS 364-day Credit Facility

On July 26, 2016, we entered into an unsecured revolving 364-day credit agreement, which we refer to as the EUS 364-day Credit Facility, with Enbridge (U.S.) Inc., or 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, (1) on a revolving basis for a 364-day period and (2) 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 based, at our election, 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.

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 (1) debt or equity securities in a registered public offering, or (2) limited partnership interests in Midcoast Operating to MEP.

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, 2015, 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 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 NGLs and condensate sales and the corresponding cost of natural gas 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 (i.e., 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 of 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 interest rates or commodity prices.

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 June 30, 2016.

Date of Maturity & Contract Type	Accounting Treatment	Notional	Average Fixed Rate(1)	Fair Value(2) at June 30, 2016	Fair Value(2) at December 31, 2015
			(dollars in millions)		
Contracts maturing in 2017					
Interest Rate Swaps – Pay Fixed	Cash Flow Hedge	$500	2.21%	$ (4.2)	$ (7.0)
Contracts maturing in 2018					
Interest Rate Swaps – Pay Fixed	Cash Flow Hedge	$810	2.24%	$ (12.8)	$ (6.6)
Contracts maturing in 2019					
Interest Rate Swaps – Pay Fixed	Cash Flow Hedge	$620	2.96%	$ (12.5)	$ (6.0)
Contracts settling prior to maturity					
2016 – Pre-issuance Hedges	Cash Flow Hedge	$500	4.21%	$(129.8)	$(80.4)
2017 – Pre-issuance Hedges	Cash Flow Hedge	$500	3.69%	$ (97.9)	$(49.2)
2018 – Pre-issuance Hedges	Cash Flow Hedge	$350	3.08%	$ (43.7)	$(12.2)

(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 June 30, 2016 and December 31, 2015, 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 $4.7 million and $3.9 million at June 30, 2016 and December 31, 2015, 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 June 30, 2016 and December 31, 2015.

	At June 30, 2016						At December 31, 2015	
			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 2016								
Swaps								
Receive variable/pay fixed	Natural Gas	16,287	$ 3.08	$ 3.48	$—	$ —	$ —	$ —
	NGL	1,203,400	$30.79	$31.48	$1.4	$(2.2)	$ 0.2	$ (8.4)
	Crude Oil	304,800	$49.52	$66.64	$0.3	$(5.6)	$ —	$(17.5)
Receive fixed/pay variable	NGL	2,513,400	$23.59	$22.79	$5.7	$(3.7)	$18.3	$ (0.2)
	Crude Oil	831,672	$57.16	$49.39	$8.2	$(1.7)	$25.4	$ —
Receive variable/pay variable	Natural Gas	6,536,000	$ 3.18	$ 3.15	$0.3	$(0.1)	$ 0.1	$ (0.1)
Physical Contracts								
Receive variable/pay fixed	NGL	535,284	$26.41	$23.91	$1.4	$(0.1)	$ —	$ (0.2)
	Crude Oil	—	$ —	$ —	$—	$ —	$ —	$ (0.2)
Receive fixed/pay variable	NGL	1,165,923	$19.12	$21.91	$0.2	$(3.4)	$ 1.9	$ (0.2)
Receive variable/pay variable	Natural Gas	68,727,634	$ 2.77	$ 2.78	$0.1	$(0.8)	$ —	$ (2.8)
	NGL	6,459,247	$22.70	$22.22	$3.8	$(0.7)	$ 4.0	$ (2.4)
	Crude Oil	949,604	$44.46	$46.75	$1.0	$(3.1)	$ 0.7	$ (0.5)
Portion of contracts maturing in 2017								
Swaps								
Receive variable/pay fixed	Natural Gas	76,530	$ 2.97	$ 2.97	$—	$ —	$ —	$ —
	NGL	1,042,500	$20.93	$21.52	$1.0	$(1.6)	$ —	$ (4.5)
	Crude Oil	638,750	$52.41	$64.29	$0.2	$(7.8)	$ —	$(10.9)
Receive fixed/pay variable	NGL	1,452,500	$18.84	$19.86	$0.7	$(2.2)	$ 3.3	$ (0.1)
	Crude Oil	866,510	$59.89	$52.41	$7.7	$(1.4)	$10.9	$ —
Receive variable/pay variable	Natural Gas	12,550,000	$ 3.25	$ 3.16	$1.2	$(0.1)	$ 0.5	$ (0.2)
Physical Contracts								
Receive variable/pay fixed	NGL	45,000	$23.80	$21.95	$0.1	$ —	$ —	$ —
Receive fixed/pay variable	NGL	10,820	$28.00	$25.09	$—	$ —	$ —	$ —
Receive variable/pay variable	Natural Gas	10,067,810	$ 3.12	$ 3.10	$0.2	$ —	$ 0.1	$ —
	NGL	792,372	$28.42	$27.37	$0.9	$ —	$ —	$ —
Portion of contracts maturing in 2018								
Physical Contracts								
Receive variable/pay variable	Natural Gas	2,187,810	$ 3.04	$ 3.01	$0.1	$ —	$ 0.1	$ —
Portion of contracts maturing in 2019								
Physical Contracts								
Receive variable/pay variable	Natural Gas	2,187,810	$ 3.04	$ 3.01	$0.1	$ —	$ 0.1	$ —
Portion of contracts maturing in 2020								
Physical Contracts								
Receive variable/pay variable	Natural Gas	359,640	$ 3.29	$ 3.27	$—	$ —	$ —	$ —

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

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

(3) The fair value is determined based on quoted market prices at June 30, 2016 and December 31, 2015, 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 $0.3 million and $0.5 million at June 30, 2016 and December 31, 2015, respectively, 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 June 30, 2016 and December 31, 2015.

	At June 30, 2016						At December 31, 2015	
					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 2016								
Puts (purchased)	Natural Gas	828,000	$ 3.75	$ 3.02	$ 0.6	$ —	$ 2.1	$ —
	NGL	1,490,400	$39.29	$27.02	$19.2	$ —	$54.4	$ —
	Crude Oil	404,800	$75.91	$49.95	$10.5	$ —	$27.7	$ —
Calls (written)	Natural Gas	828,000	$ 4.98	$ 3.02	$ —	$ —	$ —	$ —
	NGL	1,490,400	$45.09	$27.02	$ —	$(0.5)	$ —	$(0.3)
	Crude Oil	404,800	$86.68	$49.95	$ —	$ —	$ —	$ —
Puts (written)	Natural Gas	828,000	$ 3.75	$ 3.02	$ —	$(0.6)	$ —	$(2.1)
	NGL	119,600	$37.04	$28.02	$ —	$(1.2)	$ —	$(1.5)
Calls (purchased)	Natural Gas	828,000	$ 4.98	$ 3.02	$ —	$ —	$ —	$ —
	NGL	119,600	$42.09	$28.02	$ 0.1	$ —	$ —	$ —
Portion of option contracts maturing in 2017								
Puts (purchased)	NGL	1,642,500	$25.90	$28.66	$ 3.3	$ —	$ 5.8	$ —
	Crude Oil	638,750	$59.86	$52.41	$ 7.8	$ —	$10.0	$ —
Calls (written)	NGL	1,642,500	$30.06	$28.66	$ —	$(4.7)	$ —	$(0.8)
	Crude Oil	638,750	$68.19	$52.41	$ —	$(1.7)	$ —	$(0.6)
Portion of option contracts maturing in 2018								
Puts (purchased)	Crude Oil	91,250	$42.00	$53.81	$ 0.3	$ —	$ —	$ —
Calls (written)	Crude Oil	91,250	$51.75	$53.81	$ —	$(0.8)	$ —	$ —

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

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

(3) The fair value is determined based on quoted market prices at June 30, 2016 and December 31, 2015, respectively, discounted using the swap rate for the respective periods to consider the time value of money. Fair values exclude credit valuation adjustment losses of approximately $0.1 million and $0.4 million at June 30, and December 31, 2015, respectively, as well as cash collateral received.

Our credit exposure for OTC derivatives is directly with our counterparty and continues until the maturity or termination of the contract. When appropriate, valuations are adjusted for various factors such as credit and liquidity considerations. The table below summarizes our derivatives balances by counterparty credit quality (any negative amounts represent our net obligations to pay the counterparty).

	June 30, 2016	December 31, 2015
	(in millions)	
Counterparty Credit Quality[1]		
AA[2]	(91.0)	(12.4)
A	(106.7)	(10.5)
Lower than A	(65.9)	(35.0)
	$(263.6)	$(57.9)

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

(2) Includes $12.6 million held of cash collateral at December 31, 2015.

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 Securities and Exchange Commission, and that such information is accumulated and communicated to our management, including our principal executive and principal financial officers, as appropriate, to allow timely decisions regarding required disclosure. Our management, with the participation of our principal executive and principal financial officers, has evaluated the effectiveness of our disclosure controls and procedures as of June 30, 2016. 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 June 30, 2016.

PART II — OTHER INFORMATION

Item 1. Legal Proceedings

Refer to Part I, Item 1. *Financial Statements*, Note 11. *Commitments and Contingencies*, which is incorporated herein by reference.

Item 1A. Risk Factors

The risk factor presented below updates and should be considered in addition to our risk factors previously disclosed in our Annual Report on Form 10-K for the fiscal year ended December 31, 2015, filed with the SEC on February 17, 2016.

Changes in, or challenges to, our rates could have a material adverse effect on our financial condition and results of operations.

The rates charged by several of our pipeline systems are regulated by the FERC or state regulatory agencies, or both. If one of these regulatory agencies, on its own initiative or due to challenges by third parties, were to lower our tariff rates, the profitability of our pipeline businesses would suffer.

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. The FERC's income tax allowance policy has been the subject of challenge, and we cannot predict whether the FERC or a reviewing court will alter the existing policy. For example, on July 1, 2016, the U.S. Court of Appeals for the District of Columbia Circuit issued a decision that calls into question a decade of FERC policy and precedent permitting regulated companies organized as pass-through entities for income tax purposes to include an allowance for income taxes in their rates. The court has remanded the case to the FERC to allow it to have an opportunity to provide a reasoned basis for its decision on income tax allowances for partnership pipelines. If the FERC's policy were to change and if the FERC were to disallow a substantial portion of our pipelines' income tax allowance, our regulated rates, and therefore our revenues and ability to make quarterly cash distributions to our unitholders, could be adversely affected.

If we were permitted to raise our tariff rates for a particular pipeline, there might be significant delay between the time the tariff rate increase is approved and the time that the rate increase actually goes into effect, which if delayed could further reduce our cash flow. Furthermore, competition from other pipeline systems may prevent us from raising our tariff rates even if regulatory agencies permit us to do so. The regulatory agencies that regulate our systems periodically implement new rules, regulations and terms and conditions of services subject to their jurisdiction. New initiatives or orders may adversely affect the rates charged for our services.

We believe that the rates we charge for transportation services on our interstate common carrier oil and open access natural gas pipelines are just and reasonable under the ICA and NGA, respectively. However, because the rates that we charge are subject to review upon an appropriately supported protest or complaint, or a regulator's own initiative, we cannot predict what rates we will be allowed to charge in the future for service on our interstate common carrier oil and open access natural gas pipelines. Furthermore, because rates charged for transportation services must be competitive with those charged by other transporters, the rates set forth in our tariffs will be determined based on competitive factors in addition to regulatory considerations.

Item 5. Other Information

On July 26, 2016, the Partnership entered into an unsecured revolving 364-day credit agreement (the ''Credit Agreement'') with EUS. The Credit Agreement 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 Credit Agreement accrue interest based, at the Partnership's 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 the Partnership's non-credit-enhanced, senior unsecured long-term debt rating at the applicable time.

The commitment under the Credit Agreement may be permanently reduced by EUS, from time to time, by up to an amount equal to the net cash proceeds to the Partnership from the sale by the Partnership of (i) debt or equity securities in a registered public offering, or (ii) limited partnership interests in Midcoast Operating, L.P. to Midcoast Energy Partners, L.P.

The Credit Agreement also includes representations, warranties, financial covenants and events of default that are consistent with those in the Partnership's 364-Day Credit Facility. Amounts borrowed under the Credit Agreement bear interest at rates that are consistent with the interest rates set forth in the Partnership's 364-Day Credit Facility.

The above description of the Credit Agreement is qualified in its entirety by reference to the complete text of such agreement filed as Exhibit 10.1 hereto, which is hereby incorporated herein by reference.

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: July 28, 2016

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

Date: July 28, 2016

By: /s/ Stephen J. Neyland
Stephen J. Neyland
Vice President — Finance
(Principal Financial Officer)

Index of Exhibits

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

Exhibit Number	Description
10.1*	Credit Agreement dated as of June 26, 2016, by and among Enbridge Energy Partners, L.P. and Enbridge (U.S.) Inc.
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(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

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

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

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

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

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

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

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

Date: July 28, 2016

By: /s/ Mark A. Maki

Mark A. Maki
President and 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(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

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

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

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

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

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

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

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

Date: July 28, 2016

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 June 30, 2016 (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: July 28, 2016

By: /s/ Mark A. Maki

Mark A. Maki
President and 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 June 30, 2016 (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: July 28, 2016

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)