
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, 2015**

OR

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

For the transition period from _____ to _____

Commission file number **1-10934**

ENBRIDGE ENERGY PARTNERS, L.P.

(Exact Name of Registrant as Specified in Its Charter)

Delaware
(State or Other Jurisdiction of
Incorporation or Organization)

39-1715850
(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 30, 2015.

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.”

This Quarterly Report on Form 10-Q includes forward-looking statements, which are statements that frequently use words such as “anticipate,” “believe,” “continue,” “could,” “estimate,” “expect,” “forecast,” “intend,” “may,” “plan,” “position,” “projection,” “should,” “strategy,” “target,” “will” and similar words. Although we believe that such forward-looking statements are reasonable based on currently available information, such statements involve risks, uncertainties and assumptions and are not guarantees of performance. Future actions, conditions or events and future results of operations may differ materially from those expressed in these forward-looking statements. Any forward-looking statement made by us in this Quarterly Report on Form 10-Q speaks only as of the date on which it is made, and we undertake no obligation to publicly update any forward-looking statement. Many of the factors that will determine these results are beyond the Partnership’s 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) changes in or challenges to our tariff rates, (7) changes in laws or regulations to which we are subject, including compliance with environmental and operational safety regulations that may increase costs of system integrity testing and maintenance; and (8) 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, 2014, 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,	
	2015	2014	2015	2014
	(unaudited; in millions, except per unit amounts)			
Operating revenues:				
Commodity sales (Note 12)	\$ 702.7	\$1,275.5	\$1,503.6	\$2,817.8
Commodity sales – affiliate (Notes 10 and 12)	28.4	66.9	50.2	124.1
Transportation and other services (Note 12)	548.5	509.6	1,123.2	971.8
Transportation and other services – affiliate (Note 10)	33.5	19.1	64.7	37.0
	1,313.1	1,871.1	2,741.7	3,950.7
Operating expenses:				
Commodity costs (Notes 5 and 12)	647.5	1,221.4	1,408.7	2,679.9
Commodity costs – affiliate (Note 10)	23.1	38.4	41.0	68.6
Environmental costs, net of recoveries (Note 11)	(0.8)	38.2	—	43.2
Operating and administrative (Notes 6 and 11)	91.5	107.3	189.7	203.9
Operating and administrative – affiliate (Note 10)	115.7	117.3	234.6	237.7
Power (Note 12)	57.2	54.2	120.8	104.6
Depreciation and amortization (Note 6)	129.5	113.4	257.9	217.2
Goodwill impairment (Note 7)	246.7	—	246.7	—
Asset impairment (Note 6)	12.3	—	12.3	—
	1,322.7	1,690.2	2,511.7	3,555.1
Operating income (loss)	(9.6)	180.9	230.0	395.6
Interest expense, net (Notes 8 and 12)	78.0	80.2	126.3	157.1
Allowance for equity used during construction (Note 16)	17.3	12.6	40.3	33.3
Other income (Note 10)	6.0	1.2	11.9	0.4
Income (loss) before income tax expense (benefit)	(64.3)	114.5	155.9	272.2
Income tax expense (benefit) (Note 13)	(3.8)	2.0	(1.4)	4.0
Net income (loss)	(60.5)	112.5	157.3	268.2
Less: Net income attributable to:				
Noncontrolling interest (Note 10)	10.0	42.4	61.3	78.7
Series 1 preferred unit distributions	22.5	22.5	45.0	45.0
Accretion of discount on Series 1 preferred units	4.1	3.7	8.0	7.3
Net income (loss) attributable to general and limited partner ownership interests in Enbridge Energy Partners, L.P.	\$ (97.1)	\$ 43.9	\$ 43.0	\$ 137.2
Net income (loss) allocable to common units and i-units	\$ (149.4)	\$ 5.0	\$ (63.5)	\$ 63.9
Net income (loss) per common unit and i-unit (basic) (Note 2)	\$ (0.44)	\$ 0.02	\$ (0.18)	\$ 0.19
Weighted average common units and i-units outstanding (basic)	339.9	327.6	336.3	327.0
Net income (loss) per common unit and i-unit (diluted) (Note 2)	\$ (0.44)	\$ 0.02	\$ (0.18)	\$ 0.19
Weighted average common units and i-units outstanding (diluted)	339.9	327.6	336.3	327.0

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,	
	2015	2014	2015	2014
	(unaudited; in millions)			
Net income (loss)	\$(60.5)	\$112.5	\$157.3	\$ 268.2
Other comprehensive income (loss), net of tax expense of \$0.0 million (Note 12)	96.6	(66.0)	(50.2)	(136.1)
Comprehensive income	36.1	46.5	107.1	132.1
Less: Comprehensive income attributable to:				
Noncontrolling interest (Note 10)	10.0	42.4	61.3	78.7
Series 1 preferred unit distributions	22.5	22.5	45.0	45.0
Accretion of discount on Series 1 preferred units	4.1	3.7	8.0	7.3
Other comprehensive loss allocated to noncontrolling interest	(1.9)	(0.3)	(2.6)	(0.3)
Comprehensive income (loss) attributable to general and limited partner ownership interests in Enbridge Energy Partners, L.P.	\$ 1.4	\$(21.8)	\$ (4.6)	\$ 1.4

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

ENBRIDGE ENERGY PARTNERS, L.P.

CONSOLIDATED STATEMENTS OF CASH FLOWS

	For the six months ended June 30,	
	2015	2014
	(unaudited; in millions)	
Cash provided by operating activities:		
Net income	\$ 157.3	\$ 268.2
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization (Note 6)	257.9	217.2
Derivative fair value net losses (Note 12)	39.5	24.7
Inventory market price adjustments (Note 5)	5.3	3.3
Goodwill impairment (Note 7)	246.7	—
Environmental costs, net of recoveries (Note 11)	(1.0)	38.0
Distributions from investments in joint ventures (Note 10)	11.6	1.0
Equity earnings from investments in joint ventures (Note 10)	(11.6)	(1.0)
Deferred income taxes (Note 13)	(3.7)	1.3
State income taxes	1.7	1.8
Allowance for equity used during construction (Note 16)	(40.3)	(33.3)
Asset impairment (Note 6)	12.3	—
Other	4.1	0.5
Changes in operating assets and liabilities, net of acquisitions:		
Receivables, trade and other	45.7	9.1
Due from General Partner and affiliates	(62.7)	5.3
Accrued receivables	158.9	51.8
Inventory (Note 5)	(1.3)	(75.7)
Current and long-term other assets (Note 12)	(33.0)	(16.5)
Due to General Partner and affiliates	66.9	(6.0)
Accounts payable and other (Notes 4 and 12)	(56.6)	(63.8)
Environmental liabilities (Note 11)	(21.6)	(62.9)
Accrued purchases	(114.8)	(3.2)
Interest payable	1.2	1.4
Property and other taxes payable	(15.6)	(1.6)
Net cash provided by operating activities	646.9	359.6
Cash used in investing activities:		
Additions to property, plant and equipment (Notes 6 and 15)	(994.9)	(1,309.0)
Acquisitions (Note 3)	(85.0)	—
Changes in restricted cash (Note 10)	78.6	36.1
Investments in joint ventures (Note 10)	(2.5)	(28.1)
Distributions from investments in joint ventures in excess of cumulative earnings	6.7	17.7
Other	0.8	(3.7)
Net cash used in investing activities	(996.3)	(1,287.0)
Cash provided by financing activities:		
Net proceeds from unit issuances (Note 9)	294.8	—
Distributions to partners (Note 9)	(403.8)	(356.9)
Repayments to General Partner (Note 10)	(306.0)	(6.0)
Net borrowings (repayments) under credit facility (Note 8)	(300.0)	140.0
Net commercial paper borrowings (Note 8)	644.9	765.0
Contributions from noncontrolling interest (Notes 9 and 10)	502.6	612.9
Distributions to noncontrolling interest (Notes 9 and 10)	(171.2)	(42.5)
Net cash provided by financing activities	261.3	1,112.5
Net increase (decrease) in cash and cash equivalents	(88.1)	185.1
Cash and cash equivalents at beginning of year	197.9	164.8
Cash and cash equivalents at end of period	\$ 109.8	\$ 349.9

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

ENBRIDGE ENERGY PARTNERS, L.P.

CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

	June 30, 2015	December 31, 2014
	(unaudited; in millions)	
ASSETS		
Current assets:		
Cash and cash equivalents (Note 4)	\$ 109.8	\$ 197.9
Restricted cash (Notes 3, 10 and 12)	34.4	97.0
Receivables, trade and other, net of allowance for doubtful accounts of \$1.5 million and \$1.8 million at June 30, 2015 and December 31, 2014, respectively	0.2	46.2
Due from General Partner and affiliates	104.1	41.4
Accrued receivables	101.4	260.3
Inventory (Note 5)	90.2	94.2
Other current assets (Note 12)	190.7	218.4
	630.8	955.4
Property, plant and equipment, net (Notes 6 and 16)	16,541.3	15,692.7
Goodwill (Note 7)	—	246.7
Intangible assets, net	288.9	254.8
Other assets, net (Note 12)	552.2	597.3
	\$18,013.2	\$17,746.9
LIABILITIES AND PARTNERS' CAPITAL		
Current liabilities:		
Due to General Partner and affiliates (Note 10)	\$ 210.7	\$ 143.7
Accounts payable and other (Notes 4, 12 and 16)	769.5	777.7
Environmental liabilities (Note 11)	113.5	141.7
Accrued purchases	260.9	375.7
Interest payable	75.8	74.6
Property and other taxes payable (Note 13)	80.9	96.5
Note payable to General Partner (Note 10)	—	306.0
	1,511.3	1,915.9
Long-term debt (Note 8)	7,020.6	6,675.2
Due to General Partner and affiliates (Note 10)	193.3	148.3
Other long-term liabilities (Notes 6, 11, 12 and 13)	274.1	278.1
	8,999.3	9,017.5
Commitments and contingencies (Note 11)		
Partners' capital: (Notes 9 and 10)		
Series 1 preferred units (48,000,000 authorized and issued at June 30, 2015 and December 31, 2014)	1,183.6	1,175.6
Class D units (66,100,000 authorized and issued at June 30, 2015 and December 31, 2014)	2,517.6	2,516.8
Class E units (18,114,975 authorized and issued at June 30, 2015)	778.3	—
Class A common units (262,208,428 and 254,208,428 authorized and issued at June 30, 2015 and December 31, 2014)	—	235.5
Class B common units (7,825,500 authorized and issued at June 30, 2015 and December 31, 2014)	—	—
i-units (70,404,588 and 68,305,187 authorized and issued at June 30, 2015 and December 31, 2014)	517.3	712.6
Incentive distribution units (1,000 authorized and issued at June 30, 2015 and December 31, 2014)	495.0	493.0
General Partner	185.7	198.3
Accumulated other comprehensive loss (Note 12)	(259.0)	(211.4)
Total Enbridge Energy Partners, L.P. partners' capital	5,418.5	5,120.4
Noncontrolling interest (Note 10)	3,595.4	3,609.0
Total partners' capital	9,013.9	8,729.4
	\$18,013.2	\$17,746.9

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

ENBRIDGE ENERGY PARTNERS, L.P.

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, 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, 2015, our results of operations for the three and six months ended June 30, 2015 and 2014, and our cash flows for the six months ended June 30, 2015 and 2014. We derived our consolidated statement of financial position as of December 31, 2014, from the audited financial statements included in our Annual Report on Form 10-K for the fiscal year ended December 31, 2014. Our results of operations for the three and six months ended June 30, 2015 and 2014, should not be taken as indicative of the results to be expected for the full year due to seasonal fluctuations in the supply of and demand for 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, 2014.

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:

<u>Distribution Targets</u>	<u>Portion of Quarterly Distribution Per Unit</u>	<u>Percentage Distributed to General Partner and IDUs⁽¹⁾</u>	<u>Percentage Distributed to Limited partners</u>
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.

Equity Restructuring Transaction

On July 1, 2014, we entered into an equity restructuring transaction, or Equity Restructuring, with the General Partner in which the General Partner irrevocably waived its right to receive cash distributions and allocations of items of income, gain, deduction and loss in excess of 2% in respect of its general partner interest in the incentive distribution rights, or Previous IDRs, in exchange for the issuance to a wholly-owned subsidiary of the General Partner of (1) 66.1 million units of a new class of limited partner interests designated as Class D units, and (2) 1,000 units of a new class of limited partner interests designated as Incentive Distribution Units, or IDUs. Prior to this transaction, and for the three and six months ended June 30, 2014, we allocated distributions to the General Partner and limited partners as follows:

<u>Distribution Targets</u>	<u>Portion of Quarterly Distribution Per Unit</u>	<u>Percentage Distributed to General Partner</u>	<u>Percentage Distributed to Limited partners</u>
Minimum Quarterly Distribution	Up to \$0.295	2%	98%
First Target Distribution	> \$0.295 to \$0.35	15%	85%
Second Target Distribution	> \$0.35 to \$0.495	25%	75%
Over Second Target Distribution	In excess of \$0.495	50%	50%

ENBRIDGE ENERGY PARTNERS, L.P.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (unaudited)

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

Alberta Clipper Drop Down

On January 2, 2015, we completed a transaction to acquire from our General Partner the remaining 66.7% interest in the U.S. portion of the Alberta Clipper Pipeline. The consideration consisted of issuance to the General Partner of 18,114,975 units of a new class of limited partner interests designated as Class E units. For more information, please refer to Note 9. *Partners' Capital* of our consolidated financial statements.

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

	<u>For the three months ended June 30,</u>		<u>For the six months ended June 30,</u>	
	<u>2015</u>	<u>2014</u>	<u>2015</u>	<u>2014</u>
	(in millions, except per unit amounts)			
Net income (loss)	\$ (60.5)	\$ 112.5	\$ 157.3	\$ 268.2
Less Net income (loss) attributable to:				
Noncontrolling interest	(10.0)	(42.4)	(61.3)	(78.7)
Series 1 preferred unit distributions	(22.5)	(22.5)	(45.0)	(45.0)
Accretion of discount on Series 1 preferred units	(4.1)	(3.7)	(8.0)	(7.3)
Net income (loss) attributable to general and limited partner interests in Enbridge Energy Partners, L.P.	(97.1)	43.9	43.0	137.2
Less distributions:				
Incentive distributions	(5.1)	(38.0)	(8.5)	(71.2)
Distributed earnings attributed to our General Partner	(5.2)	(4.5)	(10.2)	(8.1)
Distributed earnings attributed to Class D and Class E units	(49.1)	—	(97.1)	—
Total distributed earnings to our General Partner, Class D and Class E units and IDUs	(59.4)	(42.5)	(115.8)	(79.3)
Total distributed earnings attributed to our common units and i-units	(198.5)	(182.2)	(392.0)	(359.9)
Total distributed earnings	(257.9)	(224.7)	(507.8)	(439.2)
Overdistributed earnings	\$(355.0)	\$(180.8)	\$(464.8)	\$(302.0)
Weighted average common units and i-units outstanding	339.9	327.6	336.3	327.0
Basic and diluted earnings per unit:				
Distributed earnings per common unit and i-unit ⁽¹⁾	\$ 0.58	\$ 0.56	\$ 1.17	\$ 1.10
Overdistributed earnings per common unit and i-unit ⁽²⁾	(1.02)	(0.54)	(1.35)	(0.91)
Net income (loss) per common unit and i-unit (basic and diluted) ⁽³⁾	\$ (0.44)	\$ 0.02	\$ (0.18)	\$ 0.19

⁽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, 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. For the three and six months ended June 30, 2014, 43,201,310 anti-dilutive Preferred units were excluded from the if-converted method of calculating diluted earnings per unit.

ENBRIDGE ENERGY PARTNERS, L.P.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (unaudited)

3. ACQUISITIONS

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

On February 27, 2015, Midcoast Energy Partners, L.P., or MEP, acquired the midstream business of New Gulf Resources, LLC, or NGR, in Leon, Madison and Grimes Counties, Texas for \$85.1 million in cash and a contingent future payment of up to \$17.0 million. During the three months ended June 30, 2015, the purchase price was reduced to \$85.0 million to reflect a \$0.1 million purchase price adjustment in accordance with the final settlement statement received from NGR. Of the \$85.0 million purchase price, \$20.0 million was placed into escrow, pending the resolution of a legal matter and NGR's completion of additional wells connecting to our system. Since the acquisition date, MEP has released \$4.0 million from escrow and paid it to NGR. The remaining \$16.0 million in escrow has been classified as "Restricted cash" in our consolidated statements of financial position as of June 30, 2015.

If NGR is able to deliver volumes into the system at certain tiered volume levels over a five-year period, MEP will be obligated to make future tiered payments up to \$17.0 million. This could result in a maximum total purchase price of \$102.0 million. The potential payment is considered 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 is remeasured on a fair value basis each quarter until the performance bonus is paid or expires. At June 30, 2015, contingent consideration of \$2.4 million, which includes \$0.1 million in accretion, is included in "Other long-term liabilities" in our consolidated statements of financial position.

The acquisition consisted of a natural gas gathering system that is currently in operation moving equity and third-party production. This acquisition strengthened MEP's position into the Eaglebine play, and will continue to allow them to offer gathering and processing services while leveraging assets on their existing footprint. Funding was provided by us and MEP, based on our proportionate ownership percentages in Midcoast Operating, L.P., or Midcoast Operating, at the time of acquisition, which was 48.4% and 51.6%, respectively. This business is part of our Natural Gas segment.

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 \$13.0 million at June 30, 2015, and \$17.9 million at December 31, 2014, are included in "Accounts payable and other" on our consolidated statements of financial position. At December 31, 2014, we reclassified book overdrafts of \$40.0 million to "Accounts payable and other" on our consolidated statement of financial position. We did not have any book overdrafts at June 30, 2015.

5. INVENTORY

Our inventory is comprised of the following:

	June 30, 2015	December 31, 2014
	(in millions)	
Materials and supplies	\$ 2.2	\$ 2.2
Crude oil inventory	5.7	13.2
Natural gas and NGL inventory	82.3	78.8
	<u>\$90.2</u>	<u>\$94.2</u>

"Commodity costs" on our consolidated statements of income include charges totaling \$0.7 million and \$1.5 million for the three months ended June 30, 2015 and 2014 respectively, and \$5.3 million and \$3.3 million for the six months ended June 30, 2015 and 2014, respectively, that we recorded to reduce the cost basis of our inventory of natural gas and NGLs, to reflect the current market value.

ENBRIDGE ENERGY PARTNERS, L.P.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (unaudited)

6. PROPERTY, PLANT AND EQUIPMENT

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

	June 30, 2015	December 31, 2014
	(in millions)	
Land	\$ 52.3	\$ 44.2
Rights-of-way	861.2	851.8
Pipelines	9,726.6	9,585.4
Pumping equipment, buildings and tanks ⁽¹⁾	3,475.2	3,261.8
Compressors, meters and other operating equipment	2,122.7	2,072.7
Vehicles, office furniture and equipment ⁽¹⁾	313.4	278.9
Processing and treating plants	629.3	516.0
Construction in progress	2,363.1	1,857.1
Total property, plant and equipment	19,543.8	18,467.9
Accumulated depreciation	(3,002.5)	(2,775.2)
Property, plant and equipment, net	<u>\$16,541.3</u>	<u>\$15,692.7</u>

⁽¹⁾ During the second quarter 2015, management reclassified \$135.0 million related to rail facilities from “Vehicles, office furniture and equipment” to “Pumping equipment, buildings, and tanks” to better reflect the way in which these assets are analyzed. This change has been retrospectively adjusted for all periods presented.

In May 2015, MEP approved a plan to sell its non-core Tinsley crude oil pipeline, storage facilities, and docks with a total carrying amount of \$16.8 million and its non-core Louisiana propylene pipeline with no remaining carrying value. These assets are part of our Natural Gas segment. As of June 30, 2015, we reclassified these assets as held for sale in “Other current assets” on our consolidated statements of financial position at its fair value, net of estimated cost to sell of \$4.5 million. We ceased recognizing depreciation expense on these assets upon reclassification. As a result, we recorded a \$12.3 million expected loss on disposal from sale of these assets during the second quarter of 2015. These non-cash impairment charges are included in “Asset impairment” on our consolidated statements of income.

7. GOODWILL

Goodwill represents the excess of the purchase price of an entity over the estimated fair value of the assets acquired and liabilities assumed. Our goodwill originated from acquisitions that are fully associated with our natural gas business. As of December 31, 2014, the carrying amount of goodwill was \$246.7 million.

We test our goodwill for impairment annually or more frequently if events or changes in circumstances indicate that it is more likely than not that the fair value of a reporting unit is less than its carrying value. Due to adverse market conditions facing our business, we learned from producers that reductions in drilling will be sustained and prolonged due to continued low prices for natural gas and NGLs. As a result, we determined that the impact on our forecasted operating profits and cash flows for the natural gas reporting unit for the next five years would be significantly reduced.

As a result, we performed the first step of our goodwill impairment analysis and determined that the carrying value of the natural gas reporting unit exceeded fair value. We completed the second step of the goodwill impairment analysis comparing the implied fair value of the reporting unit to the carrying amount of that goodwill and determined that goodwill was completely impaired in the amount of \$246.7 million. The impairment charge is presented as “Goodwill impairment” on our consolidated statement of income for the three and six months ended June 30, 2015.

We measure the fair value of our reporting units primarily by using a discounted cash flow analysis. In addition, we also consider overall market capitalization of our business, cash flow measurement data and other factors. Our estimate of fair value required us to use significant unobservable inputs representative of a Level 3 fair value measurement, including assumptions related to the future performance of our natural gas reporting unit.

ENBRIDGE ENERGY PARTNERS, L.P.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (unaudited)

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, 2015, before the effect of our interest rate hedging activities. Our indebtedness with related parties is discussed in Note 10. *Related Party Transactions*.

	<u>Interest Rate</u>	<u>June 30, 2015</u>	<u>December 31, 2014</u>
(in millions)			
EEP debt obligations:			
Commercial Paper ⁽¹⁾	0.763%	\$1,257.6	\$ 612.3
Credit Facilities due 2016 – 2019	1.22% – 3.25%	810.0	1,160.0
Senior Notes due 2016	5.875%	300.0	300.0
Senior Notes due 2018	7.000%	100.0	100.0
Senior Notes due 2018	6.500%	400.0	400.0
Senior Notes due 2019	9.875%	500.0	500.0
Senior Notes due 2020	5.200%	500.0	500.0
Senior Notes due 2021	4.200%	600.0	600.0
Senior Notes due 2028	7.125%	100.0	100.0
Senior Notes due 2033	5.950%	200.0	200.0
Senior Notes due 2034	6.300%	100.0	100.0
Senior Notes due 2038	7.500%	400.0	400.0
Senior Notes due 2040	5.500%	550.0	550.0
Junior subordinated notes due 2067	8.050%	400.0	400.0
MEP debt obligations:			
MEP Credit Agreement	2.413%	410.0	360.0
MEP Series A Senior Notes due 2019	3.560%	75.0	75.0
MEP Series B Senior Notes due 2021	4.040%	175.0	175.0
MEP Series C Senior Notes due 2024	4.420%	150.0	150.0
Total Principal of Debt Obligations		<u>7,027.6</u>	<u>6,682.3</u>
Other:			
Unamortized Discount		(7.0)	(7.1)
Total Long Term Debt		<u>\$7,020.6</u>	<u>\$6,675.2</u>

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

Interest Cost

Our interest cost for the three and six months ended June 30, 2015, and 2014, is comprised of the following:

	<u>For the three months ended June 30,</u>		<u>For the six months ended June 30,</u>	
	<u>2015</u>	<u>2014</u>	<u>2015</u>	<u>2014</u>
(in millions)				
Interest expense	\$78.0	\$80.2	\$126.3	\$157.1
Less: Interest capitalized	<u>6.1</u>	<u>10.2</u>	<u>18.3</u>	<u>24.1</u>
Interest cost incurred	<u>\$84.1</u>	<u>\$90.4</u>	<u>\$144.6</u>	<u>\$181.2</u>

The \$30.8 million decrease in interest expense for the six months ended June 30, 2015, as compared with the same period in 2014 was primarily due to changes to interest expense from ineffectiveness on hedging instruments.

ENBRIDGE ENERGY PARTNERS, L.P.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (unaudited)

8. DEBT – (continued)

Credit Facilities and Commercial Paper

We have a committed multi-year senior unsecured revolving credit facility, which we refer to as the Credit Facility, and a 364-day credit agreement, which we refer to as the 364-Day Credit Facility. We refer to our Credit Facility and our 364-Day Credit Facility as the Credit Facilities. The Credit Facility permits aggregate borrowings of up to, at any one time outstanding, \$1.975 billion. The maturity date on the Credit Facility is September 26, 2019; however, \$175.0 million of commitments will expire on the original maturity date of September 26, 2018. At June 30, 2015, we had \$810.0 million outstanding under our Credit Facilities at a weighted average interest rate of 1.59%. During the six months ended June 30, 2015, we had net repayments of \$350.0 million, which includes gross borrowings of \$6,885.0 million and gross repayments of \$7,235.0 million.

On July 2, 2015, we amended our 364-Day Credit Facility to extend the revolving credit termination date from July 3, 2015 to July 1, 2016. We further amended the 364-Day Credit Facility, to decrease the aggregate commitments from \$650.0 million to \$525.0 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. After the amendment to the 364-Day Credit Facility, the Credit Facilities provide an aggregate amount of approximately \$2.5 billion of bank credit, as of July 2, 2015, which we use to fund our general activities and working capital needs.

In addition, we have a credit agreement with Enbridge (U.S.) Inc., an affiliate of Enbridge, or the EUS 364-day Credit Facility, that permits aggregate borrowing of up to, at any one time outstanding, \$750.0 million, which is discussed in Note 9. *Related Party Transactions*.

We have a commercial paper program that 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. At June 30, 2015, we had approximately \$1,257.6 million in principal amount of commercial paper outstanding at a weighted average interest rate of 0.76%, excluding the effect of our interest rate hedging activities. Under our commercial paper program, we had net borrowings of approximately \$644.9 million during the six months ended June 30, 2015, which includes gross borrowings of \$5,717.3 million and gross repayments of \$5,072.4 million. At December 31, 2014, we had approximately \$612.3 million in principal amount of commercial paper outstanding at a weighted average interest rate of 0.50%, excluding the effect of our interest rate hedging activities. 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.

We have 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 \$220.0 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.

The amounts we may borrow under the terms of our Credit Facilities are reduced by the face amount of our letters of credit outstanding. 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.

ENBRIDGE ENERGY PARTNERS, L.P.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (unaudited)

8. DEBT – (continued)

At June 30, 2015, we had approximately \$990.2 million available under the terms of our Credit Facilities and the EUS 364-day Credit Facility, determined as follows:

	(in millions)
Total credit available under our Credit Facilities ⁽¹⁾	\$2,625.0
Total credit available under the EUS 364-day Credit Facility	750.0
Less: Amounts outstanding under our Credit Facilities	810.0
Principal amount of commercial paper outstanding	1,257.6
EUS 364-day Credit Facility ⁽²⁾	—
Letters of credit outstanding	317.2
Total amount available at June 30, 2015	<u>\$ 990.2</u>

⁽¹⁾ On July 2, 2015, we had an amendment to our 364-day Credit Facility. After the amendment on a pro-forma basis our total credit available under our Credit Facilities is \$2,500.0 million, and the total amount available under the Credit Facilities and the EUS 364-day Credit Facility, less amounts outstanding, is \$865.2 million.

⁽²⁾ Refer to Note 9. *Related Party Transactions* for further details regarding the EUS 364-day Credit Facility.

As of June 30, 2015, we were in compliance with the terms of all of our financial covenants under our Credit Facilities and the EUS 364-day Credit Facility.

MEP Credit Agreement

MEP, Midcoast Operating, and their material domestic 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, at any one time outstanding, \$850.0 million. 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. On September 30, 2014, MEP amended the MEP Credit Agreement to extend the maturity date from November 13, 2016, to September 30, 2017; however, \$140.0 million of commitments will expire on the original maturity date of November 13, 2016.

At June 30, 2015, MEP had \$410.0 million in outstanding borrowings under the MEP Credit Agreement at a weighted average interest rate of 2.4%. Under the MEP Credit Agreement, MEP had net borrowings of approximately \$50.0 million during the six months ended June 30, 2015, which includes gross borrowings of \$2,505.0 million and gross repayments of \$2,455.0 million. As of June 30, 2015, MEP was in compliance with the terms of its financial covenants.

MEP Senior Notes

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

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, 2015, and December 31, 2014, 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 above since we have the ability and the intent to refinance the amounts outstanding on a long-term basis.

ENBRIDGE ENERGY PARTNERS, L.P.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (unaudited)

8. DEBT – (continued)

The approximate fair values of our fixed-rate debt obligations was \$5.0 billion and \$5.1 billion at June 30, 2015, and December 31, 2014, 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, 2015.

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 30, 2015	May 8, 2015	May 15, 2015	\$0.5700	\$249.9	\$39.5	\$0.8	\$209.6
January 29, 2015	February 6, 2015	February 13, 2015	\$0.5700	\$233.9	\$38.9	\$0.8	\$194.2

⁽¹⁾ We issued 2,099,401 i-units to Enbridge Management, the sole owner of our i-units, during 2015 in lieu of cash distributions.

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

Changes in Partners' Capital

The following table presents significant changes in partners' capital accounts attributable to our General Partner and limited partners as well as the noncontrolling interests in our consolidated subsidiaries, Enbridge Energy, Limited Partnership, or OLP, the North Dakota Pipeline Company LLC, or NDPC, and MEP, for the six months ended June 30, 2015 and 2014. The noncontrolling interest in the OLP arises from the joint funding arrangements with our General Partner and its affiliate to finance: (1) expansion of our Lakehead system to transport crude oil to destinations in the Midwest United States, which we refer to as the Eastern Access Projects; and (2) further expansion of our Lakehead system to transport crude oil between Neche, North Dakota and Superior, Wisconsin, which we refer to as the Mainline Expansion Projects. Noncontrolling interest in NDPC arises from our agreement with Williston Basin Pipeline LLC, or Williston, an affiliate of Marathon Petroleum Corporation, to, among other things, become a member of NDPC. Williston funds 37.5% of the Sandpiper Project that will expand the North Dakota feeder system to Superior, Wisconsin mainline system terminal. Noncontrolling interest in MEP arises from its public unitholders' ownership interests in MEP.

ENBRIDGE ENERGY PARTNERS, L.P.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (unaudited)

9. PARTNERS' CAPITAL – (continued)

	For the six months ended June 30,	
	2015	2014
	(in millions)	
Series 1 Preferred interests		
Beginning balance	\$1,175.6	\$1,160.7
Net income	45.0	45.0
Accretion of discount on preferred units	8.0	7.3
Distribution payable	(45.0)	(45.0)
Ending balance	<u>\$1,183.6</u>	<u>\$1,168.0</u>
General and limited partner interests		
Beginning balance	\$4,156.2	\$4,637.7
Proceeds from issuance of partnership interests, net of costs	294.8	—
Net income	43.0	137.2
Distributions	(403.8)	(356.9)
Acquisition of noncontrolling interest in subsidiary	403.7	—
Ending balance	<u>\$4,493.9</u>	<u>\$4,418.0</u>
Accumulated other comprehensive loss		
Beginning balance	\$ (211.4)	\$ (76.6)
Changes in fair value of derivative financial instruments reclassified to earnings	(3.5)	16.6
Changes in fair value of derivative financial instruments recognized in other comprehensive loss	(44.1)	(152.4)
Ending balance	<u>\$ (259.0)</u>	<u>\$ (212.4)</u>
Noncontrolling interest		
Beginning balance	\$3,609.0	\$1,975.6
Capital contributions	502.6	612.9
Acquisition of noncontrolling interest in subsidiary	(403.7)	—
Other comprehensive loss allocated to noncontrolling interest	(2.6)	(0.3)
Net income	61.3	78.7
Distributions to noncontrolling interest	(171.2)	(42.5)
Ending balance	<u>\$3,595.4</u>	<u>\$2,624.4</u>
Total partners' capital at end of period	<u>\$9,013.9</u>	<u>\$7,998.0</u>

Alberta Clipper Drop Down

On January 2, 2015, we completed a transaction, or the Drop Down, pursuant to which we acquired the remaining 66.7% interest in the U.S. segment of the Alberta Clipper Pipeline from our General Partner. The consideration consisted of approximately 18,114,975 units of a new class of limited partner interests designated as Class E units issued to the General Partner. The Class E units were issued at a notional value of \$38.31 per unit, which was determined based on the trailing five-day volume-weighted average price of our Class A common units as of that date, which was the date on which we and the General Partner entered into a contribution agreement setting forth the terms of the Drop Down. In addition, we repaid the borrowings outstanding of \$306.0 million on the A1 Term Note owed to the General Partner.

The Class E units are entitled to the same distributions as Class A common units held by the public and are convertible into Class A common units on a one-for-one basis at the General Partner's option. The Class E units were not entitled to distributions with respect to the quarter ended December 31, 2014. The Class E units are redeemable at our option after 30 years, if not earlier converted by the General Partner.

ENBRIDGE ENERGY PARTNERS, L.P.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (unaudited)

9. PARTNERS' CAPITAL – (continued)

The Class E units have a liquidation preference equal to their notional value at December 23, 2014 of \$38.31 per unit. If the aggregate Earnings Before Interest, Taxes, Depreciation and Amortization, or EBITDA, attributable to the Series AC interest in the OLP for calendar years 2015 and 2016 is less than \$265.9 million, then 1,305,142 of the Class E units will be cancelled by us effective as of June 15, 2017, for no consideration and will no longer be deemed outstanding for any purposes under our partnership agreement.

In addition, during each taxable year during the period from January 1, 2015 through December 31, 2037 in which a majority of the Class E units issued on the closing date of the Drop Down remain outstanding, holders of Class A common units, Class B common units and Class D units (including those held by the General Partner) will be specially allocated items of gross income that would otherwise be allocated to holders of Class E units, to the extent that such an amount of gross income exists, in an annual amount equal to \$40.0 million. The annual amount of such allocation will be reduced to \$20.0 million for each taxable year beginning after December 31, 2037.

We recorded the Drop Down as an equity transaction. No loss on the acquisition of the remaining ownership interests in Alberta Clipper was recognized in our consolidated statement of income or comprehensive income. We reduced the carrying value of the related "Noncontrolling interest" in Alberta Clipper of \$403.7 million to zero. In addition, we recorded the Class E units at their fair value of \$767.7 million. We determined the fair value of the Class E units using a market approach based upon the closing price of the Class A common units as of January 2, 2015, adjusted for differences in specific rights such as the liquidation preference granted to the Class E units and other economic factors that would affect the fair value of the Class E units.

The difference of \$364.0 million between the fair value of the Class E units and the carrying value of the noncontrolling interest in Alberta Clipper was recorded as a reduction to the carrying amounts of the capital accounts of the Class A and Class B common units, the i-units and the General Partner interest on a pro rata basis. The recording of this transaction reduced the carrying values of the Class A and Class B common units below zero. Our partnership agreement requires that such capital account deficits are brought back to zero, or "cured," by additional allocations from the capital accounts of the i-units and General Partner interest on a pro-rata basis. As a result the i-units' and General Partner interest's capital balances were reduced by \$46.7 million and \$1.0 million, respectively, to cure the deficit balances in the Class A and Class B common units. This initial curing did not impact earnings allocated to either the i-units or the General Partner interest.

Additional Curing

During the three months ended June 30, 2015, the carrying amounts for the capital accounts of the Class A and Class B common units were reduced below zero due to distributions to partners exceeding earnings. As a result, the capital balances of the i-units and general partner interests were reduced by \$62.2 million and \$1.4 million, respectively, to cure the deficit balances in the Class A and Class B common units.

Shelf-Registration Statement

From time to time, we may seek to satisfy liquidity needs through the offer and sale of debt or equity securities in public offerings. In February 2015, we filed with the SEC a new automatically effective shelf registration statement, or the 2015 Shelf, on Form S-3 that replaced our prior shelf registration statement which expired in December 2014. The 2015 Shelf allows us to issue an unlimited amount of equity and debt securities in underwritten public offerings.

ENBRIDGE ENERGY PARTNERS, L.P.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (unaudited)

9. PARTNERS' CAPITAL – (continued)

Issuance of Class A Common Units

In March 2015, we sold 8 million Class A common units in an underwritten public offering pursuant to the 2015 Shelf for net proceeds of \$288.8 million. The following table presents the net proceeds from our Class A common unit issuances for the current year. The proceeds from the March 2015 offering were used to fund a portion of our capital expansion projects and for general partnership purposes.

<u>2015 Issuance Date</u>	<u>Number of Class A common units Issued</u>	<u>Offering Price per Class A common unit</u>	<u>Net Proceeds to the Partnership⁽¹⁾</u>	<u>General Partner Contribution⁽²⁾</u>	<u>Net Proceeds Including General Partner Contribution</u>
		(in millions, except units and per unit amount)			
March	8,000,000	\$36.70	\$288.8	\$6.0	\$294.8

⁽¹⁾ Net of underwriters' fees and discounts, commissions and issuance expenses.

⁽²⁾ Contributions made by the General Partner to maintain its 2% general partner interest.

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 Inc., or 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.

Financing Transactions with Affiliates

EUS 364-day Credit Facility

On March 9, 2015, 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 March 7, 2016 and including the option to term the revolving loan for a period of 364-days following the termination date, the credit facility becomes non-revolving thus extending the term to March 6, 2017. There is no outstanding balance as of June 30, 2015 under the EUS 364-day Credit Facility.

The commitment under the EUS 364-day Credit Facility may be permanently reduced by EUS, from time to time, by up to an amount equal to the net cash proceeds to us from the sale by us of (1) debt or equity securities in a registered public offering, or (2) limited partnership interests in Midcoast Operating to MEP.

ENBRIDGE ENERGY PARTNERS, L.P.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (unaudited)

10. RELATED PARTY TRANSACTIONS – (continued)

Distribution from MEP

The following table presents distributions paid by MEP to its Class A common unitholders and us during the six months ended June 30, 2015, representing the noncontrolling interest in MEP.

<u>Distribution Declaration Date</u>	<u>Distribution Payment Date</u>	<u>Amount Paid to EEP</u>	<u>Amount Paid to the noncontrolling interest</u> (in millions)	<u>Total MEP Distribution</u>
April 29, 2015	May 15, 2015	\$ 8.6	\$ 7.4	\$16.0
January 28, 2015	February 13, 2015	<u>8.5</u>	<u>7.3</u>	<u>15.8</u>
		<u>\$17.1</u>	<u>\$14.7</u>	<u>\$31.8</u>

Distribution to Series AC Interests

On January 2, 2015, we completed a transaction, or the Drop Down, pursuant to which we acquired the remaining 66.7% interest in the U.S. segment of the Alberta Clipper Pipeline from our General Partner.

The following table presents the final ownership distribution for the fourth quarter of 2014 paid by the OLP to our General Partner and its affiliate on February 13, 2015, representing the noncontrolling interest in the Series AC, and to us, as the holders of the Series AC 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 AC interests and pursuant to the OLP's partnership agreement, was distributed to Series AC partners of record as of the last day of the fourth quarter.

<u>Distribution Declaration Date</u>	<u>Distribution Payment Date</u>	<u>Amount Paid to Partnership</u>	<u>Amount paid to the noncontrolling interest</u> (in millions)	<u>Total Series AC Distribution</u>
January 29, 2015	February 13, 2015	\$13.7	\$27.5	\$41.2

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 U.S. 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. Our General Partner owns 75% of the EA interests, and the projects are jointly funded by our General Partner at 75% and us at 25%.

Our General Partner made equity contributions totaling \$98.3 million and \$360.8 million to the OLP during the six months ended June 30, 2015 and 2014, 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 to our General Partner and its affiliate during the six months ended June 30, 2015, 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.

ENBRIDGE ENERGY PARTNERS, L.P.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (unaudited)

10. RELATED PARTY TRANSACTIONS – (continued)

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 distributions. Please refer to Note 18. *Subsequent Events* of our consolidated financial statements.

<u>Distribution Declaration Date</u>	<u>Distribution Payment Date</u>	<u>Amount Paid to EEP</u>	<u>Amount Paid to the noncontrolling interest</u>	<u>Total Series EA Distribution</u>
			(in millions)	
April 30, 2015	May 15, 2015	\$17.5	\$ 52.3	\$ 69.8
January 29, 2015	February 13, 2015	<u>22.3</u>	<u>67.0</u>	<u>89.3</u>
		<u>\$39.8</u>	<u>\$119.3</u>	<u>\$159.1</u>

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 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. Our General Partner owns 75% of the ME interests, and the projects are jointly funded by our General Partner at 75% and us at 25%, under the Mainline Expansion Joint Funding Agreement, which is similar to the Eastern Access Joint Funding Agreement.

Our General Partner has made equity contributions totaling \$360.7 million and \$177.7 million to the OLP for the six months ended June 30, 2015, and 2014, 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 to our General Partner and its affiliate during the six months ended June 30, 2015, 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.

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 ME distributions. Please refer to Note 18. *Subsequent Events* of our consolidated financial statements.

<u>Distribution Declaration Date</u>	<u>Distribution Payment Date</u>	<u>Amount Paid to EEP</u>	<u>Amount Paid to the noncontrolling interest</u>	<u>Total Series ME Distribution</u>
			(in millions)	
April 30, 2015	May 15, 2015	\$1.5	\$4.5	\$ 6.0
January 29, 2015	February 13, 2015	<u>1.8</u>	<u>5.2</u>	<u>7.0</u>
		<u>\$3.3</u>	<u>\$9.7</u>	<u>\$13.0</u>

Noncontrolling Interests

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

	<u>For the three months ended June 30,</u>		<u>For the six months ended June 30,</u>	
	<u>2015</u>	<u>2014</u>	<u>2015</u>	<u>2014</u>
	(in millions)		(in millions)	
Alberta Clipper Interests	\$ —	\$11.6	\$ (0.8)	\$21.7
Eastern Access Interests	45.1	27.2	89.9	48.8
U.S. Mainline Expansion Interests	27.9	5.7	44.4	10.1
Midcoast Energy Partners, L.P.	<u>(63.0)</u>	<u>(2.1)</u>	<u>(72.2)</u>	<u>(1.9)</u>
Total	<u>\$ 10.0</u>	<u>\$42.4</u>	<u>\$ 61.3</u>	<u>\$78.7</u>

ENBRIDGE ENERGY PARTNERS, L.P.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (unaudited)

10. RELATED PARTY TRANSACTIONS – (continued)

Sale of Accounts Receivable

We sold and derecognized receivables to a wholly-owned subsidiary of Enbridge for \$917.8 million and \$1,236.0 million for the three months ended June 30, 2015 and 2014, respectively, and \$2,013.7 million and \$2,532.7 million for the six months ended June 30, 2015 and 2014, respectively. We received cash proceeds of \$917.5 million and \$1,235.7 million for the three months ended June 30, 2015 and 2014, respectively and \$2,013.1 million and \$2,532.1 million for the six months ended June 30, 2015 and 2014, respectively. As of June 30, 2015, \$340.5 million of the receivables were outstanding and had not been collected on behalf of the Enbridge subsidiary.

Consideration for the receivables sold is equivalent to the carrying value of the receivables less a discount for credit risk. The difference between the carrying value of the receivables sold and the cash proceeds received is recognized in “Operating and administrative — affiliate” expense in our consolidated statements of income. For the three and six months ended June 30, 2015 and 2014, the cost stemming from the discount on the receivables sold was not material.

As of June 30, 2015 and December 31, 2014, we had \$6.9 million and \$71.9 million, respectively, included in “Restricted cash” on our consolidated statements of financial position, consisting of cash collections related to the receivables sold that have yet to be remitted to the Enbridge subsidiary as of June 30, 2015.

Affiliate Revenues and Purchases

We purchase natural gas from third-parties, which subsequently generates operating revenues from sales to Enbridge and its affiliates. These transactions are entered into at the market price on the date of sale and 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 natural gas from Enbridge and its affiliates for sale to third-parties at market prices on the date of purchase. Purchases of natural gas, 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, 2015 and December 31, 2014, was \$376.2 million and \$380.6 million, respectively, which is included on our consolidated statements of financial position in “Other assets, net.” We recognized equity income of \$5.9 million and \$2.3 million for the three months ended June 30, 2015 and 2014, respectively, and \$11.6 million and \$1.0 million for the six months ended June 30, 2015 and 2014, respectively, in “Other income” on our consolidated statements of income related to our investment in the system.

We incurred \$4.6 million and \$6.1 million for the three months ended June 30, 2015 and 2014, respectively, and \$8.3 million and \$11.4 million for the six months ended June 30, 2015 and 2014, 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 business has made commitments to transport up to 120,000 barrels per day, or Bpd, of NGLs on the Texas Express NGL system from 2015 to 2022. The current commitment level is 27,000 Bpd.

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

ENBRIDGE ENERGY PARTNERS, L.P.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (unaudited)

11. COMMITMENTS AND CONTINGENCIES – (continued)

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, 2015 and December 31, 2014, we had \$113.5 million and \$141.7 million, respectively, included in “Environmental liabilities,” and \$61.9 million and \$60.1 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.

Griffith Terminal Crude Oil Release

On February 25, 2014, a release of approximately 975 barrels of crude oil occurred within the Griffith Terminal in Griffith, Indiana. A repair plan has been reviewed with PHMSA and repair work has been completed. The released oil was fully contained within our facility and substantially all of the free product was recovered. The released oil did not affect the local community, wildlife or water supply. As of June 30, 2015, we had no remaining estimated liability.

Lakehead Lines 6A & 6B Crude Oil Releases

Line 6A Crude Oil Release

On September 9, 2010, a crude oil release occurred on Line 6A in Romeoville, Illinois, caused by a third party water pipeline failure which damaged our pipelines. One claim was filed against us and our affiliates by the State of Illinois in Illinois state court in connection with this crude oil release. On February 20, 2015, we agreed to a consent order releasing us from any claims, liability, or penalties.

Line 6B Crude Oil Release

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

We continue to 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.

On March 14, 2013, we received an order from the EPA, which we refer to as the Order, that required additional containment and active recovery of submerged oil relating to the Line 6B crude oil release. In February 2015 the EPA acknowledged our completion of the Order.

In November 2014, regulatory authority was transferred from the EPA to the Michigan Department of Environmental Quality, or MDEQ. The MDEQ has oversight over submerged oil reassessment, sheen management and sediment trap monitoring and maintenance activities, through a Kalamazoo River Residual Oil Monitoring and Maintenance Work Plan.

In May 2015, Enbridge reached a settlement with the MDEQ and the Michigan Attorney General’s offices regarding the Line 6B crude oil release. As stipulated in the settlement, Enbridge agrees to: (1) provide at least 300 acres of wetland through restoration, creation, or banked wetland credits, to remain as wetland in perpetuity, (2) pay \$5.0 million as mitigation for impacts to the banks, bottomlands, and flow of Talmadge Creek and the Kalamazoo

ENBRIDGE ENERGY PARTNERS, L.P.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (unaudited)

11. COMMITMENTS AND CONTINGENCIES – (continued)

River for the purpose of enhancing the Kalamazoo River watershed and restoring stream flows in the River, (3) continue to reimburse the State of Michigan for costs arising from oversight of Enbridge activities since the release, and (4) continue monitoring, restoration and invasive species control within state-regulated wetlands affected by the release and associated response activities. The timing of these activities is based upon the work plans approved by the State of Michigan. Through June 30, 2015, Enbridge has reimbursed the State of Michigan more than \$12.0 million in costs.

As of June 30, 2015, our total cost estimate for the Line 6B crude oil release remains at \$1.2 billion.

For purposes of estimating our expected losses associated with the Line 6B crude oil release, we have included those costs that we considered probable and that could be reasonably estimated at June 30, 2015. 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 *Line 6B 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 total estimated loss for the cleanup, remediation and restoration associated with the Line 6B crude oil release include the following:

	(in millions)
Response personnel and equipment	\$ 549.5
Environmental consultants	227.0
Professional, regulatory and other	431.5
Total	<u>\$1,208.0</u>

For the six months ended June 30, 2015 and 2014, we made payments of \$20.1 million and \$65.0 million, respectively, for costs associated with the Line 6B crude oil release. As of June 30, 2015 and December 31, 2014, we had a remaining estimated liability of \$170.9 million and \$195.2 million, respectively.

Line 6B Fines and Penalties

At June 30, 2015, our remaining estimated costs related to the Line 6B crude oil release included \$47.5 million in fines and penalties. Of this amount, \$40.0 million relates to civil penalties under the Clean Water Act of the United States. While no final fine or penalty has been assessed or agreed to date, we believe that, based on the best information available at this time, the \$40.0 million represents an estimate of the minimum amount which may be assessed, excluding costs of injunctive relief that may be agreed to with the relevant governmental agencies. Given the complexity of settlement negotiations, which we expect will continue, and the limited information available to assess the matter, we are unable to reasonably estimate the final penalty which might be incurred or to reasonably estimate a range of outcomes at this time. Injunctive relief is likely to include further measures directed toward enhancing spill prevention, leak detection, and emergency response to environmental events, and the cost of compliance with such measures, when combined with any fine or penalty, could be material. We have entered into a tolling agreement with the applicable governmental agencies and discussions with these governmental agencies regarding fines, penalties, and injunctive relief are ongoing.

In June 2015, Enbridge reached a separate agreement with the United States of America (Federal Natural Resources Damages Trustees), State of Michigan (State Natural Resources Damages Trustees), Match-E-Be-Nash-She-Wish Band of the

ENBRIDGE ENERGY PARTNERS, L.P.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (unaudited)

11. COMMITMENTS AND CONTINGENCIES – (continued)

Potawatomi Indians, and the Nottawaseppi Huron Band of the Potawatomi Indians to pay approximately \$3.9 million that we had accrued to cover a variety of projects, including the restoration of 175 acres of oak savanna in Fort Custer State Recreation Area and wild rice beds along the Kalamazoo River.

Insurance

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

A majority of the costs incurred for the crude oil release for Line 6B 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, 2015, costs related to Line 6B exceeded the limits of the coverage available under this insurance policy. As of June 30, 2015, 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 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 and amended our lawsuit such that it included 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 in the arbitration.

We are pursuing recovery of the costs associated with the Line 6A crude oil release from third parties; however, there can be no assurance that any such recovery will be obtained. Additionally, fines and penalties would not be covered under our existing insurance policy.

Enbridge renewed its comprehensive property and liability insurance programs, under which we are insured through April 30, 2016, with a liability program aggregate limit of \$860.0 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. Approximately five actions or claims are pending against us and our affiliates in state and federal courts in connection with the Line 6B crude oil release. Based on the current status of these cases, we do not expect the outcome of these actions to be material to our results of operations or financial condition.

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

ENBRIDGE ENERGY PARTNERS, L.P.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (unaudited)

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 NGL and condensate sales and the corresponding commodity costs of natural gas and natural gas liquids we purchase for processing. Our interest rate risk exposure results from changes in interest rates on our variable rate debt and exists at the corporate level where our variable rate debt obligations are issued. Our exposure to commodity price risk exists within each of our segments. We use derivative financial instruments, such as futures, forwards, swaps, options and other financial instruments with similar characteristics, to manage the risks associated with market fluctuations in interest rates and commodity prices, as well as to reduce volatility in our cash flows. Based on our risk management policies, all of our derivative financial instruments, including those that do not qualify 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, 2015	December 31, 2014
	(in millions)	
Other current assets	\$ 126.8	\$ 185.5
Other assets, net	54.0	93.3
Accounts payable and other ⁽¹⁾	(305.1)	(315.4)
Other long-term liabilities	(112.2)	(124.6)
Due from general partner and affiliates	—	0.3
	<u>\$ (236.5)</u>	<u>\$ (160.9)</u>

⁽¹⁾ Includes \$11.5 million and \$28.4 million held of cash collateral at June 30, 2015 and December 31, 2014, respectively.

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

In September 2014, we amended the maturity date on certain interest rate hedges of future debt issuances that were originally set to mature in 2014 and 2016 to better reflect the expected timing of future debt issuances. The ineffective portion of the hedges fair value in relation to the hedged future debt issuances is recognized in income at the amendment date and each quarter end. For the three and six months ended June 30, 2015, we recognized in interest expense unrealized gains for hedge ineffectiveness of approximately \$3.7 million and \$29.8 million, respectively, associated with interest rate hedges that were originally set to mature in 2014 and 2016.

During the first quarter of 2014, we determined that a portion of forecasted short term debt transactions were not expected to occur, due to changing funding requirements. Since we will require less short-term debt than previously forecasted, we terminated several of our existing interest rate hedges used to lock-in interest rates on our short-term debt issuances as these hedges no longer met the cash flow hedging requirements. These terminations resulted in realized losses of \$0.8 million for the six months ended June 30, 2014. We had no similar terminations of our cash flow hedges for the six months ended June 30, 2015.

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NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (unaudited)

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

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

	June 30, 2015	December 31, 2014
	(in millions)	
Counterparty Credit Quality⁽¹⁾		
AAA	\$ 0.1	\$ 0.1
AA ⁽²⁾	(68.5)	(49.8)
A	(84.5)	(129.1)
Lower than A	(83.6)	17.9
	<u>\$ (236.5)</u>	<u>\$ (160.9)</u>

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

⁽²⁾ Includes \$11.5 million and \$28.4 million held of cash collateral at June 30, 2015 and December 31, 2014, respectively.

As the net value of our derivative financial instruments has decreased in response to changes in forward commodity prices 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, 2015 and December 31, 2014, we held \$11.5 million and \$28.4 million of cash collateral on our asset exposures, respectively. Cash collateral is classified as “Restricted cash” in our consolidated statements of financial position. When we are in a position of posting collateral to cover our counterparties’ exposure to our non-performance, the collateral is provided through letters of credit, which are not reflected above.

We have provided letters of credit totaling \$316.6 million and \$329.6 million relating to our liability exposures pursuant to the margin thresholds in effect at June 30, 2015 and December 31, 2014, 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 to 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 at the lowest level of investment grade at June 30, 2015, we would have been required to provide additional letters of credit in the amount of \$7.1 million.

ENBRIDGE ENERGY PARTNERS, L.P.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (unaudited)

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

At June 30, 2015 and December 31, 2014, we had credit concentrations in the following industry sectors, as presented below:

	<u>June 30, 2015</u>	<u>December 31, 2014</u>
	<u>(in millions)</u>	
United States financial institutions and investment banking entities ⁽¹⁾	\$ (186.9)	\$ (147.1)
Non-United States financial institutions	(77.3)	(54.2)
Other	27.7	40.4
	<u>\$ (236.5)</u>	<u>\$ (160.9)</u>

⁽¹⁾ Includes \$11.5 million and \$28.4 million held of cash collateral at June 30, 2015 and December 31, 2014, respectively.

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

Effect of Derivative Instruments on the Consolidated Statements of Financial Position

	<u>Financial Position Location</u>	<u>Asset Derivatives</u>		<u>Liability Derivatives</u>	
		<u>Fair Value at</u>		<u>Fair Value at</u>	
		<u>June 30, 2015</u>	<u>December 31, 2014</u>	<u>June 30, 2015</u>	<u>December 31, 2014</u>
<u>(in millions)</u>					
Derivatives designated as hedging instruments:⁽¹⁾					
Interest rate contracts	Other current assets	\$ —	\$ —	\$ —	\$ —
Interest rate contracts	Other assets	4.3	—	—	—
Interest rate contracts	Accounts payable and other	—	—	(261.2)	(241.0)
Interest rate contracts	Other long-term liabilities	—	—	(95.8)	(102.0)
Commodity contracts	Other current assets	12.9	26.1	—	—
Commodity contracts	Other assets	—	2.1	—	—
		<u>17.2</u>	<u>28.2</u>	<u>(357.0)</u>	<u>(343.0)</u>
Derivatives not designated as hedging instruments:					
Commodity contracts	Other current assets	113.9	159.4	—	—
Commodity contracts	Other assets	49.7	91.2	—	—
Commodity contracts	Accounts payable and other ⁽²⁾	—	—	(32.4)	(46.0)
Commodity contracts	Other long-term liabilities	—	—	(16.4)	(22.6)
Commodity contracts	Due from general partner and affiliates	—	0.3	—	—
		<u>163.6</u>	<u>250.9</u>	<u>(48.8)</u>	<u>(68.6)</u>
Total derivative instruments		<u>\$180.8</u>	<u>\$279.1</u>	<u>\$ (405.8)</u>	<u>\$ (411.6)</u>

⁽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 \$11.5 million and \$28.4 million held of cash collateral at June 30, 2015 and December 31, 2014, respectively.

ENBRIDGE ENERGY PARTNERS, L.P.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (unaudited)

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

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. Also included in AOCI, as of June 30, 2015 and December 31, 2014, are unrecognized losses of approximately \$25.4 million and \$28.4 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 and 2014, unrealized commodity hedge gains of \$0.6 million and losses of \$0.2 million, respectively, were de-designated as a result of the hedges no longer meeting hedge accounting criteria. We estimate that approximately \$252.9 million, representing unrealized net losses from our cash flow hedging activities based on pricing and positions at June 30, 2015, will be reclassified from AOCI to earnings during the next 12 months.

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

Derivatives in Cash Flow Hedging Relationships	Amount of Gain (Loss) Recognized in AOCI on Derivative (Effective Portion)	Location of Gain (Loss) Reclassified from AOCI to Earnings (Effective Portion)	Amount of Gain (Loss) Reclassified from AOCI to Earnings (Effective Portion)	Location of Gain (Loss) Recognized in Earnings on Derivative (Ineffective Portion and Amount Excluded from Effectiveness Testing) ⁽¹⁾	Amount of Gain (Loss) Recognized in Earnings on Derivative (Ineffective Portion and Amount Excluded from Effectiveness Testing) ⁽¹⁾
(in millions)					
For the three 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	<u>\$ 95.5</u>		<u>\$ 4.2</u>		<u>\$ 3.7</u>
For the three months ended June 30, 2014					
Interest rate contracts	\$ (65.4)	Interest expense	\$ (3.4)	Interest expense	\$ (5.3)
Commodity contracts	(3.2)	Commodity Costs	(3.8)	Commodity Costs	(1.1)
Total	<u>\$ (68.6)</u>		<u>\$ (7.2)</u>		<u>\$ (6.4)</u>
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	<u>\$ (53.3)</u>		<u>\$ 7.2</u>		<u>\$ 28.4</u>
For the six months ended June 30, 2014					
Interest rate contracts	\$(137.1)	Interest expense	\$ (8.1)	Interest expense	\$(11.0)
Commodity contracts	(3.3)	Commodity Costs	(10.3)	Commodity Costs	0.6
Total	<u>\$ (140.4)</u>		<u>\$ (18.4)</u>		<u>\$ (10.4)</u>

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

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NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (unaudited)

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

Components of Accumulated Other Comprehensive Income/(Loss)

	Cash Flow Hedges	
	2015	2014
	(in millions)	
Balance at January 1,	\$(211.4)	\$ (76.6)
Other Comprehensive Income before reclassifications ⁽¹⁾	(44.1)	(152.4)
Amounts reclassified from AOCI ⁽²⁾⁽³⁾	(3.5)	16.6
Net other comprehensive loss	<u>\$ (47.6)</u>	<u>\$(135.8)</u>
Balance at June 30,	<u><u>\$(259.0)</u></u>	<u><u>\$(212.4)</u></u>

- ⁽¹⁾ Excludes NCI gain of \$1.1 million and NCI loss of \$2.1 million reclassified from AOCI at June 30, 2015 and 2014, respectively.
⁽²⁾ Excludes NCI loss of \$3.7 million and NCI gain of \$1.8 million reclassified from AOCI at June 30, 2015 and 2014, respectively.
⁽³⁾ For additional details on the amounts reclassified from AOCI, reference the *Reclassifications from Accumulated Other Comprehensive Income* table below.

Reclassifications from Accumulated Other Comprehensive Income

	For the three months ended June 30,		For the six months ended June 30,	
	2015	2014	2015	2014
	(in millions)			
Losses (gains) on cash flow hedges:				
Interest Rate Contracts ⁽¹⁾	\$ 2.9	\$3.4	\$ 8.3	\$ 8.1
Commodity Contracts ⁽²⁾⁽³⁾⁽⁴⁾	(5.4)	3.2	(11.8)	8.5
Total Reclassifications from AOCI	<u><u>\$(2.5)</u></u>	<u><u>\$6.6</u></u>	<u><u>\$(3.5)</u></u>	<u><u>\$16.6</u></u>

- ⁽¹⁾ Loss reported within “Interest expense, net” in the consolidated statements of income.
⁽²⁾ Loss (gain) reported within “Commodity costs” in the consolidated statements of income.
⁽³⁾ Excludes NCI loss of \$1.7 million and gain of \$0.6 million reclassified from AOCI for the three months ending June 30, 2015 and 2014, respectively.
⁽⁴⁾ Excludes NCI loss of \$3.7 million and gain of \$1.8 million reclassified from AOCI for the six months ending June 30, 2015 and 2014, respectively.

Effect of Derivative Instruments on Consolidated Statements of Income

Derivatives Not Designated as Hedging Instruments	Location of Gain or (Loss) Recognized in Earnings	For the three months ended June 30,		For the six months ended June 30,	
		2015	2014	2015	2014
		Amount of Gain or (Loss) Recognized in Earnings⁽¹⁾⁽²⁾			
		(in millions)			
Commodity contracts	Transportation and other services ⁽³⁾	\$(2.7)	\$ (5.5)	\$ —	\$ (7.6)
Commodity contracts	Commodity sales	2.1	3.1	(15.2)	3.1
Commodity contracts	Commodity sales – affiliate	(0.1)	0.1	(0.3)	0.5
Commodity contracts	Commodity costs ⁽⁴⁾	(8.6)	(13.4)	3.5	(19.4)
Commodity contracts	Power	—	0.2	—	0.5
Total		<u><u>\$(9.3)</u></u>	<u><u>\$(15.5)</u></u>	<u><u>\$(12.0)</u></u>	<u><u>\$(22.9)</u></u>

- ⁽¹⁾ Does not include settlements associated with derivative instruments that settle through physical delivery.
⁽²⁾ Includes only net gains or losses associated with those derivatives that do not qualify for hedge accounting treatment and does not include the ineffective portion of derivatives that are designated as hedging instruments.
⁽³⁾ Includes settlement gains (losses) of \$5.6 million and \$(0.1) million for the three months ended June 30, 2015 and 2014, respectively, and settlement gains of \$12.2 million and \$0.3 million for the six months ended June 30, 2015 and 2014, respectively.
⁽⁴⁾ Includes settlement gains (losses) of \$18.0 million and \$(0.3) million for the three months ended June 30, 2015 and 2014, respectively, and settlement gains (losses) of \$43.7 million and \$(8.8) million for the six months ended June 30, 2015 and 2014, respectively.

ENBRIDGE ENERGY PARTNERS, L.P.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (unaudited)

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

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, 2015				
Description:	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 (in millions)	Gross Amount Not Offset in the Statement of Financial Position ⁽¹⁾	Net Amount

Derivatives	\$180.8	\$—	\$180.8	\$(56.1)	\$124.7
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	As of December 31, 2014				
Description:	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 (in millions)	Gross Amount Not Offset in the Statement of Financial Position ⁽¹⁾	Net Amount

Derivatives	\$279.1	\$—	\$279.1	\$(91.8)	\$187.3
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⁽¹⁾ Includes \$11.5 million and \$28.4 million of cash collateral held at June 30, 2015 and December 31, 2014, respectively.

Offsetting of Financial Liabilities and Derivative Liabilities

	As of June 30, 2015				
Description:	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 (in millions)	Gross Amount Not Offset in the Statement of Financial Position ⁽¹⁾	Net Amount

Derivatives	\$(417.3)	\$—	\$(417.3)	\$56.1	\$(361.2)
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	As of December 31, 2014				
Description:	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 (in millions)	Gross Amount Not Offset in the Statement of Financial Position ⁽¹⁾	Net Amount

Derivatives	\$(440.0)	\$—	\$(440.0)	\$91.8	\$(348.2)
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⁽¹⁾ Includes \$11.5 million and \$28.4 million of cash collateral at June 30, 2015 and December 31, 2014, respectively.

Inputs to Fair Value Derivative Instruments

The following table sets forth by level within the fair value hierarchy our financial assets and liabilities that were accounted for at fair value on a recurring basis as of June 30, 2015 and December 31, 2014. We classify financial assets and liabilities in their entirety based on the lowest level of input that is significant to the fair value measurement. Our

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NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (unaudited)

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

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, 2015				December 31, 2014			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
	(in millions)							
Interest rate contracts . . .	\$—	\$(352.6)	\$ —	\$(352.6)	\$—	\$(343.0)	\$ —	\$(343.0)
Commodity contracts:								
Financial	—	19.2	20.1	39.3	—	41.6	42.7	84.3
Physical	—	—	12.3	12.3	—	—	19.5	19.5
Commodity options	—	—	76.0	76.0	—	—	106.7	106.7
	—	(333.4)	108.4	(225.0)	—	(301.4)	168.9	(132.5)
Cash collateral				(11.5)				(28.4)
Total				\$(236.5)				\$(160.9)

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.

Qualitative Information about Level 3 Fair Value Measurements

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

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NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (unaudited)

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

Quantitative Information About Level 3 Fair Value Measurements

Contract Type	Fair Value at June 30, 2015 ⁽²⁾	Valuation Technique	Unobservable Input	Range ⁽¹⁾			Units
				Lowest	Highest	Weighted Average	
(in millions)							
Commodity Contracts – Financial							
Natural Gas	\$ 0.7	Market Approach	Forward Gas Price	2.54	3.59	2.96	MMBtu
NGLs	\$ 19.4	Market Approach	Forward NGL Price	0.20	1.25	0.60	Gal
Commodity Contracts – Physical							
Natural Gas	\$ 2.0	Market Approach	Forward Gas Price	2.52	4.29	2.91	MMBtu
Crude Oil	\$ (0.2)	Market Approach	Forward Crude Price	47.45	63.00	59.84	Bbl
NGLs	\$ 10.5	Market Approach	Forward NGL Price	0.20	1.31	0.49	Gal
Commodity Options							
Natural Gas, Crude and NGLs . .	\$ 76.0	Option Model	Option Volatility	10%	62%	35%	
Total Fair Value	<u>\$108.4</u>						

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

(2) Fair values include credit valuation adjustment losses of approximately \$0.3 million.

Quantitative Information About Level 3 Fair Value Measurements

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

(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 \$1.0 million.

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NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (unaudited)

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, 2015 to June 30, 2015. No transfers of assets between any of the Levels occurred during the period.

	<u>Commodity Financial Contracts</u>	<u>Commodity Physical Contracts</u>	<u>Commodity Options</u>	<u>Total</u>
	(in millions)			
Beginning balance as of January 1, 2015	\$ 42.7	\$ 19.5	\$106.7	\$168.9
Transfer in (out) of Level 3 ⁽¹⁾	—	—	—	—
Gains or losses included in earnings:				
Reported in Commodity sales	—	3.8	—	3.8
Reported in Commodity costs	(2.2)	13.2	(3.9)	7.1
Gains or losses included in other comprehensive income:				
Reported in Other comprehensive income (loss), net of tax	(0.4)	—	—	(0.4)
Purchases, issuances, sales and settlements:				
Purchases	—	—	—	—
Sales	—	—	2.0	2.0
Settlements ⁽²⁾	(20.0)	(24.2)	(28.8)	(73.0)
Ending balance as June 30, 2015.	<u>\$ 20.1</u>	<u>\$ 12.3</u>	<u>\$ 76.0</u>	<u>\$108.4</u>
Amounts reported in Commodity sales.	<u>\$ —</u>	<u>\$(15.5)</u>	<u>\$ —</u>	<u>\$(15.5)</u>
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	<u>\$ —</u>	<u>\$ 5.6</u>	<u>\$ —</u>	<u>\$ 5.6</u>
Reported in Commodity costs	<u>\$ (2.0)</u>	<u>\$ 5.8</u>	<u>\$ (0.9)</u>	<u>2.9</u>

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

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

ENBRIDGE ENERGY PARTNERS, L.P.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (unaudited)

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, 2015 and December 31, 2014.

Commodity	Notional ⁽¹⁾	At June 30, 2015				At December 31, 2014		
		Wtd. Average Price ⁽²⁾		Fair Value ⁽³⁾		Fair Value ⁽³⁾		
		Receive	Pay	Asset	Liability	Asset	Liability	Liability
(in millions)								
Portion of contracts maturing in 2015								
<i>Swaps</i>								
Receive variable/pay fixed	Natural Gas	1,558,292	\$ 2.77	\$ 2.83	\$ 0.1	\$ (0.2)	\$ —	\$ (0.7)
	NGL	901,000	\$32.48	\$36.64	\$ 0.1	\$ (3.8)	\$ —	\$ (6.8)
	Crude Oil	504,000	\$60.30	\$84.19	\$ —	\$ (12.0)	\$ —	\$ (27.4)
Receive fixed/pay variable	Natural Gas	2,550,938	\$ 3.00	\$ 2.83	\$ 0.5	\$ —	\$ 3.7	\$ —
	NGL	1,720,600	\$38.80	\$28.84	\$17.4	\$ (0.3)	\$39.2	\$ —
	Crude Oil	961,064	\$91.18	\$60.31	\$29.5	\$ —	\$65.0	\$ —
Receive variable/pay variable . . .	Natural Gas	47,491,500	\$ 2.73	\$ 2.72	\$ 1.5	\$ (1.2)	\$ 1.5	\$ (1.7)
<i>Physical Contracts</i>								
Receive variable/pay fixed	Natural Gas	106,700	\$ 2.66	\$ 2.70	\$ —	\$ —	\$ —	\$ —
	NGL	767,000	\$11.59	\$11.40	\$ 0.2	\$ (0.1)	\$ —	\$ (3.6)
	Crude Oil	33,400	\$59.60	\$59.45	\$ —	\$ —	\$ —	\$ —
Receive fixed/pay variable	Natural Gas	209,936	\$ 2.81	\$ 2.73	\$ —	\$ —	\$ —	\$ —
	NGL	3,396,447	\$21.07	\$19.97	\$ 4.9	\$ (1.2)	\$19.8	\$ —
	Crude Oil	107,000	\$59.58	\$59.69	\$ —	\$ (0.1)	\$ 0.5	\$ —
Receive variable/pay variable . . .	Natural Gas	136,481,498	\$ 2.80	\$ 2.79	\$ 1.1	\$ (0.2)	\$ 2.2	\$ (1.0)
	NGL	8,585,747	\$23.33	\$22.75	\$ 5.6	\$ (0.6)	\$ 3.7	\$ (1.0)
	Crude Oil	911,227	\$58.61	\$58.91	\$ 1.1	\$ (1.4)	\$ 0.3	\$ (1.7)
Portion of contracts maturing in 2016								
<i>Swaps</i>								
Receive variable/pay fixed	Natural Gas	363,514	\$ 2.83	\$ 3.41	\$ —	\$ (0.2)	\$ —	\$ (0.1)
	NGL	823,500	\$28.45	\$30.70	\$ —	\$ (1.8)	\$ —	\$ —
	Crude Oil	415,950	\$62.01	\$82.69	\$ —	\$ (8.6)	\$ —	\$ (8.1)
Receive fixed/pay variable	Natural Gas	1,898,100	\$ 3.21	\$ 3.24	\$ 0.1	\$ (0.1)	\$ —	\$ —
	NGL	883,500	\$38.48	\$28.05	\$ 9.2	\$ —	\$ 9.3	\$ —
	Crude Oil	769,270	\$74.36	\$62.04	\$ 9.5	\$ (0.1)	\$ 9.1	\$ —
Receive variable/pay variable . . .	Natural Gas	50,739,000	\$ 3.01	\$ 2.99	\$ 1.6	\$ (1.0)	\$ 0.5	\$ (0.3)
<i>Physical Contracts</i>								
Receive variable/pay fixed	NGL	—	\$ —	\$ —	\$ —	\$ —	\$ —	\$ —
Receive fixed/pay variable	Natural Gas	63,850	\$ 3.11	\$ 3.06	\$ —	\$ —	\$ —	\$ —
	NGL	38,963	\$32.99	\$31.84	\$ 0.1	\$ —	\$ —	\$ —
Receive variable/pay variable . . .	Natural Gas	99,005,643	\$ 3.13	\$ 3.12	\$ 0.8	\$ —	\$ 0.7	\$ (0.4)
	NGL	9,676,152	\$21.94	\$21.76	\$ 1.8	\$ —	\$ —	\$ —
	Crude Oil	30,400	\$61.65	\$59.30	\$ 0.1	\$ —	\$ —	\$ —
Portion of contracts maturing in 2017								
<i>Swaps</i>								
Receive variable/pay fixed	Natural Gas	24,030	\$ 3.27	\$ 3.48	\$ —	\$ —	\$ —	\$ —
	NGL	547,500	\$23.14	\$25.86	\$ —	\$ (1.5)	\$ —	\$ —
	Crude Oil	547,500	\$63.62	\$66.72	\$ —	\$ (1.7)	\$ —	\$ —
Receive fixed/pay variable	NGL	547,500	\$23.59	\$23.14	\$ 0.6	\$ (0.3)	\$ 0.7	\$ —
	Crude Oil	547,500	\$66.78	\$63.62	\$ 2.1	\$ (0.4)	\$ 0.8	\$ —
Receive variable/pay variable . . .	Natural Gas	5,910,000	\$ 3.24	\$ 3.20	\$ 0.2	\$ —	\$ —	\$ —
<i>Physical Contracts</i>								
Receive variable/pay variable . . .	Natural Gas	28,097,550	\$ 3.39	\$ 3.38	\$ 0.2	\$ —	\$ 0.2	\$ (0.1)
Portion of contracts maturing in 2018								
<i>Physical Contracts</i>								
Receive variable/pay variable . . .	Natural Gas	5,787,810	\$ 3.57	\$ 3.56	\$ 0.1	\$ —	\$ —	\$ —
Portion of contracts maturing in 2019								
<i>Physical Contracts</i>								
Receive variable/pay variable . . .	Natural Gas	2,187,810	\$ 3.54	\$ 3.51	\$ —	\$ —	\$ —	\$ —
Portion of contracts maturing in 2020								
<i>Physical Contracts</i>								
Receive variable/pay variable . . .	Natural Gas	359,640	\$ 3.86	\$ 3.83	\$ —	\$ —	\$ —	\$ —

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

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

⁽³⁾ The fair value is determined based on quoted market prices at June 30, 2015 and December 31, 2014, 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 \$0.0 million and \$0.5 million at June 30, 2015 and December 31, 2014, respectively, as well as cash collateral received.

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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, 2015 and December 31, 2014.

Commodity	Notional ⁽¹⁾	At June 30, 2015			At December 31, 2014			
		Strike Price ⁽²⁾	Market Price ⁽²⁾	Fair Value ⁽³⁾		Fair Value ⁽³⁾		
				Asset	Liability	Asset	Liability	
(in millions)								
Portion of option contracts maturing in 2015								
Puts (purchased)	Natural Gas	2,024,000	\$ 3.90	\$ 2.90	\$ 2.1	\$ —	\$ 3.8	\$ —
	NGL	1,159,200	\$43.32	\$25.70	\$20.6	\$ —	\$40.2	\$ —
	Crude Oil	368,000	\$81.56	\$60.38	\$ 7.9	\$ —	\$18.8	\$ —
Calls (written)	Natural Gas	644,000	\$ 5.05	\$ 2.90	\$ —	\$ —	\$ —	\$ —
	NGL	745,200	\$45.80	\$24.93	\$ —	\$(0.1)	\$ —	\$(0.6)
	Crude Oil	368,000	\$88.39	\$60.38	\$ —	\$ —	\$ —	\$(0.4)
Puts (written)	Natural Gas	2,024,000	\$ 3.90	\$ 2.91	\$ —	\$(2.1)	\$ —	\$(3.8)
	NGL	46,000	\$77.28	\$51.86	\$ —	\$(1.2)	\$ —	\$ —
Calls (purchased)	Natural Gas	644,000	\$ 5.05	\$ 2.90	\$ —	\$ —	\$ —	\$ —
Portion of option contracts maturing in 2016								
Puts (purchased)	Natural Gas	1,647,000	\$ 3.75	\$ 3.17	\$ 1.2	\$ —	\$ 1.0	\$ —
	NGL	2,836,500	\$39.24	\$27.06	\$38.9	\$ —	\$39.3	\$ —
	Crude Oil	805,200	\$75.91	\$62.08	\$12.9	\$ —	\$14.7	\$ —
Calls (written)	Natural Gas	1,647,000	\$ 4.98	\$ 3.17	\$ —	\$(0.1)	\$ —	\$(0.1)
	NGL	2,836,500	\$45.14	\$27.06	\$ —	\$(2.8)	\$ —	\$(3.2)
	Crude Oil	805,200	\$86.68	\$62.08	\$ —	\$(0.8)	\$ —	\$(2.7)
Puts (written)	Natural Gas	1,647,000	\$ 3.75	\$ 3.17	\$ —	\$(1.2)	\$ —	\$(1.0)
	NGL	91,500	\$39.06	\$29.66	\$ —	\$(1.1)	\$ —	\$ —
Calls (purchased)	Natural Gas	1,647,000	\$ 4.98	\$ 3.17	\$ 0.1	\$ —	\$ 0.1	\$ —
	NGL	91,500	\$46.41	\$29.66	\$ 0.1	\$ —	\$ —	\$ —
Portion of option contracts maturing in 2017								
Puts (purchased)	NGL	547,500	\$21.70	\$23.14	\$ 0.8	\$ —	\$ 1.2	\$ —
	Crude Oil	547,500	\$63.00	\$63.62	\$ 4.3	\$ —	\$ 4.1	\$ —
Calls (written)	NGL	547,500	\$25.34	\$23.14	\$ —	\$(0.6)	\$ —	\$(0.7)
	Crude Oil	547,500	\$71.45	\$63.62	\$ —	\$(2.7)	\$ —	\$(3.3)

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

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

⁽³⁾ The fair value is determined based on quoted market prices at June 30, 2015 and December 31, 2014, 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 \$0.2 million and \$0.7 million at June 30, 2015 and December 31, 2014, respectively, as well as cash collateral received.

ENBRIDGE ENERGY PARTNERS, L.P.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (unaudited)

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.

<u>Date of Maturity & Contract Type</u>	<u>Accounting Treatment</u>	<u>Notional</u>	<u>Average Fixed Rate⁽¹⁾</u>	<u>Fair Value⁽²⁾ at</u>	
				<u>June 30, 2015</u>	<u>December 31, 2014</u>
<i>Contracts maturing in 2015</i>					
Interest Rate Swaps – Pay Fixed	Cash Flow Hedge	\$ 510	1.53%	\$ —	\$ (0.2)
<i>Contracts maturing in 2016</i>					
Interest Rate Swaps – Pay Fixed	Cash Flow Hedge	\$ 90	0.55%	\$ (0.1)	\$ (0.1)
<i>Contracts maturing in 2017</i>					
Interest Rate Swaps – Pay Fixed	Cash Flow Hedge	\$ 500	2.21%	\$ (11.5)	\$ (12.9)
<i>Contracts maturing in 2018</i>					
Interest Rate Swaps – Pay Fixed	Cash Flow Hedge	\$ 810	2.24%	\$ (5.1)	\$ (1.3)
<i>Contracts maturing in 2019</i>					
Interest Rate Swaps – Pay Fixed	Cash Flow Hedge	\$ 620	2.96%	\$ (4.0)	\$ (3.3)
<i>Contracts settling prior to maturity</i>					
2015 – Pre-issuance Hedges	Cash Flow Hedge	\$1,000	5.48%	\$(254.6)	\$(258.3)
2016 – Pre-issuance Hedges	Cash Flow Hedge	\$ 500	4.21%	\$ (57.1)	\$ (63.4)
2017 – Pre-issuance Hedges	Cash Flow Hedge	\$ 500	3.69%	\$ (25.6)	\$ (36.0)
2018 – Pre-issuance Hedges	Cash Flow Hedge	\$ 350	3.08%	\$ 3.7	\$ (4.9)

⁽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, 2015 and December 31, 2014, 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 \$1.7 million and \$37.4 million at June 30, 2015 and December 31, 2014, 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 computed our income tax expense by applying a Texas state income tax rate to modified gross margin. Our Texas state income tax rate was 0.4% for the six months ended June 30, 2015 and 2014. Our income tax benefit was \$3.8 million and \$1.4 million for the three and six months ended June 30, 2015, respectively. Our income tax expense was \$2.0 million and \$4.0 million for the three and six months ended June 30, 2014, respectively.

At June 30, 2015 and December 31, 2014, we included a current income tax payable of \$0.5 million and \$1.5 million, respectively, in “Property and other taxes payable” on our consolidated statements of financial position. In addition, at June 30, 2015 and December 31, 2014, we included a deferred income tax payable of \$17.9 million and \$21.7 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.

ENBRIDGE ENERGY PARTNERS, L.P.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (unaudited)

13. INCOME TAXES – (continued)

The Texas Legislature passed House Bill 32, and the tax bill was subsequently signed into law in June of 2015. The bill applies to original reports filed on or after January 1, 2016, and permanently reduces Texas franchise tax rates. Specifically, the general 1.0% rate will be reduced to 0.75%. As a result of this change, we have recorded a reduction in our deferred income tax payable reflected in “Other long-term liabilities” on our consolidated statement of financial position of approximately \$5.4 million at June 30, 2015.

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.

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

	For the three months ended June 30, 2015			
	<u>Liquids</u>	<u>Natural Gas</u>	<u>Corporate⁽¹⁾</u>	<u>Total</u>
	(in millions)			
Operating revenues:				
Commodity sales	\$ —	\$ 731.1	\$ —	\$ 731.1
Transportation and other services	533.0	49.0	—	582.0
	<u>533.0</u>	<u>780.1⁽²⁾</u>	<u>—</u>	<u>1,313.1</u>
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
	<u>261.4</u>	<u>1,057.7</u>	<u>3.6</u>	<u>1,322.7</u>
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)	<u>271.6</u>	<u>(271.7)</u>	<u>(60.4)</u>	<u>(60.5)</u>
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.	<u>\$271.6</u>	<u>\$ (271.7)</u>	<u>\$(97.0)</u>	<u>\$ (97.1)</u>

⁽¹⁾ Corporate consists of interest expense, interest income, 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 (expense) for our Natural Gas segment includes our equity investment in the Texas Express NGL system.

ENBRIDGE ENERGY PARTNERS, L.P.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (unaudited)

14. SEGMENT INFORMATION – (continued)

	For the three months ended June 30, 2014			
	Liquids	Natural Gas	Corporate ⁽¹⁾	Total
	(in millions)			
Operating revenues:				
Commodity sales	\$ —	\$1,342.4	\$ —	\$1,342.4
Transportation and other services	474.3	54.4	—	528.7
	474.3	1,396.8	—	1,871.1
Commodity costs	—	1,259.8	—	1,259.8
Environmental costs, net of recoveries	38.2	—	—	38.2
Operating and administrative	117.6	103.6	3.4	224.6
Power	54.2	—	—	54.2
Depreciation and amortization	76.6	36.8	—	113.4
	286.6	1,400.2	3.4	1,690.2
Operating income (loss)	187.7	(3.4)	(3.4)	180.9
Interest expense, net	—	—	80.2	80.2
Allowance for equity used during construction	—	—	12.6	12.6
Other income (expense)	—	2.3 ⁽²⁾	(1.1)	1.2
Income (loss) before income tax expense	187.7	(1.1)	(72.1)	114.5
Income tax expense	—	—	2.0	2.0
Net income (loss)	187.7	(1.1)	(74.1)	112.5
Less: Net income attributable to:				
Noncontrolling interest	—	—	42.4	42.4
Series 1 preferred unit distributions	—	—	22.5	22.5
Accretion of discount on Series 1 preferred units	—	—	3.7	3.7
Net income (loss) attributable to general and limited partner ownership interests in Enbridge Energy Partners, L.P.	\$187.7	\$ (1.1)	\$(142.7)	\$ 43.9

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

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

ENBRIDGE ENERGY PARTNERS, L.P.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (unaudited)

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
	<u>1,088.1</u>	<u>1,653.6</u>	<u>—</u>	<u>2,741.7</u>
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
	<u>546.3</u>	<u>1,957.8</u>	<u>7.6</u>	<u>2,511.7</u>
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.	<u>\$ 541.8</u>	<u>\$ (292.6)</u>	<u>\$(206.2)</u>	<u>\$ 43.0</u>
Total assets	<u>\$12,564.1</u>	<u>\$5,256.5⁽⁴⁾</u>	<u>\$ 192.6</u>	<u>\$18,013.2</u>
Capital expenditures (excluding acquisitions)	<u>\$ 909.0</u>	<u>\$ 104.6</u>	<u>\$ 13.9</u>	<u>\$ 1,027.5</u>

⁽¹⁾ Corporate consists of interest expense, interest income, 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 (expense) for our Natural Gas segment includes our equity investment in the Texas Express NGL system.

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

ENBRIDGE ENERGY PARTNERS, L.P.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (unaudited)

14. SEGMENT INFORMATION – (continued)

	As of and for the six months ended June 30, 2014			
	Liquids	Natural Gas	Corporate ⁽¹⁾	Total
	(in millions)			
Operating revenues:				
Commodity sales	\$ —	\$2,941.9	\$ —	\$ 2,941.9
Transportation and other services	907.0	101.8	—	1,008.8
	<u>907.0</u>	<u>3,043.7</u>	<u>—</u>	<u>3,950.7</u>
Commodity costs	—	2,748.5	—	2,748.5
Environmental costs, net of recoveries	43.2	—	—	43.2
Operating and administrative	226.0	212.5	3.1	441.6
Power	104.6	—	—	104.6
Depreciation and amortization	143.4	73.8	—	217.2
	<u>517.2</u>	<u>3,034.8</u>	<u>3.1</u>	<u>3,555.1</u>
Operating income (loss)	389.8	8.9	(3.1)	395.6
Interest expense, net	—	—	157.1	157.1
Allowance for equity used during construction	—	—	33.3	33.3
Other income (expense)	—	1.0 ⁽²⁾	(0.6)	0.4
	<u>389.8</u>	<u>9.9</u>	<u>(127.5)</u>	<u>272.2</u>
Income tax expense	—	—	4.0	4.0
Net income (loss)	<u>389.8</u>	<u>9.9</u>	<u>(131.5)</u>	<u>268.2</u>
Less: Net income attributable to:				
Noncontrolling interest	—	—	78.7	78.7
Series 1 preferred unit distributions	—	—	45.0	45.0
Accretion of discount on Series 1 preferred units	—	—	7.3	7.3
Net income (loss) attributable to general and limited partner ownership interests in Enbridge Energy Partners, L.P.	<u>\$ 389.8</u>	<u>\$ 9.9</u>	<u>\$(262.5)</u>	<u>\$ 137.2</u>
Total assets	<u>\$10,335.9</u>	<u>\$5,301.3⁽³⁾</u>	<u>\$ 426.2</u>	<u>\$16,063.4</u>
Capital expenditures (excluding acquisitions)	<u>\$ 985.0</u>	<u>\$ 105.0</u>	<u>\$ 1.5</u>	<u>\$ 1,091.5</u>

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

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

⁽³⁾ Total assets for our Natural Gas segment include \$381.6 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,	
	2015	2014
	(in millions)	
Additions to property, plant and equipment	\$ 994.9	\$1,309.0
Increase (decrease) in construction payables	32.6	(217.5)
Total capital expenditures (excluding “Investment in joint venture”)	<u>\$1,027.5</u>	<u>\$1,091.5</u>

ENBRIDGE ENERGY PARTNERS, L.P.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (unaudited)

16. REGULATORY MATTERS

Regulatory Accounting

We apply the authoritative regulatory accounting provisions to a number of our pipeline projects that meet the criteria outlined for regulated operations. The rates for Southern Access, Alberta Clipper, the Mainline Expansion Project, Eastern Access, the Line 6B 75-mile Replacement Project, Line 6B Integrity Project, and the Line 14 Project, which are currently the primary applicable projects, are based on a cost-of-service recovery model that follows the Federal Energy Regulatory Commission, or FERC, authoritative guidance and is subject to annual filing requirements with the FERC. Under our cost-of-service tolling methodology, we calculate tolls annually based on forecast volumes and costs. A difference between forecast and actual results causes an over or under recovery in any given year. These over or under recoveries are deferred through a revenue adjustment and are returned to or recovered from shippers through future rate adjustments in the following year. Under the authoritative accounting provisions applicable to our regulated operations, over or under recoveries are recognized in the financial statements in the current period. This accounting model matches earnings to the period with which they relate and conforms to how we recover our costs associated with these expansions through the annual cost-of-service filings with the FERC and through toll rate adjustments with our customers.

Due to over or under recovery revenue adjustments made in accordance with the FERC’s authoritative guidance and our cost-of-service tariff methodology, 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. The net regulatory asset or liability balance is comprised of the cumulative over and under recovery revenue adjustments made during the prior year, less any amortizations, and the cumulative over and under recovery revenue adjustments made during the current year to date. We track regulatory assets and liabilities by vintage, and our regulatory assets and liabilities are amortized on a straight-line basis over a one-year recovery period. Accordingly, amortization for a net regulatory asset or liability arising from over and under recovery adjustments related to any given calendar year does not begin until January of the following year. The changes in our net regulatory asset balance for the three and six months ended June 30, 2015 and 2014 are as follows:

	For the three months ended June 30,		For the six months ended June 30,	
	2015	2014	2015	2014
	(in millions)			
Net regulatory asset balance at beginning of period	\$(6.8)	\$ 8.1	\$ 6.0	\$ 7.7
Current period (over)/under recovery revenue adjustments	9.6	(3.5)	0.5	(1.2)
Amortization of prior year regulatory asset	(0.8)	(5.8)	(4.5)	(7.7)
Net regulatory asset (liability) balance at end of period	<u>\$ 2.0</u>	<u>\$(1.2)</u>	<u>\$ 2.0</u>	<u>\$(1.2)</u>

Other Contractual Obligations

Southern Access Pipeline

We have entered into certain contractual obligations with our customers on the Southern Access Pipeline 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. We record the liabilities associated with this contractual obligation in “Accounts payable and other,” on our consolidated statements of financial position. At June 30, 2015 and December 31, 2014 we had no qualifying volume liabilities related to the Southern Access Pipeline on our consolidated statements of financial position.

During 2013, we incurred liabilities related to contractual obligations with our customers on the Southern Access Pipeline related to qualifying volumes. We did not incur any similar liabilities during 2014. As a result, in 2013, we recorded a liability for the 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, 2014, we amortized through revenue \$2.3 million and \$4.4 million, respectively, of qualifying volume liabilities on our consolidated statements of income, with a corresponding amount reducing the contractual obligation on our consolidated statements of financial position.

ENBRIDGE ENERGY PARTNERS, L.P.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (unaudited)

16. REGULATORY MATTERS – (continued)

Alberta Clipper Pipeline

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 significantly higher than the actual property tax imposed, we are contractually obligated to refund 50% of the property tax over recovery to our customers. We record the liabilities associated with this contractual obligation in “Accounts payable and other,” on our consolidated statements of financial position. At June 30, 2015 and December 31, 2014, we had \$4.0 million and \$5.9 million, respectively, in property tax over recovery liabilities related to our Alberta Clipper Pipeline on our consolidated statements of financial position.

During 2014 and 2013, we incurred liabilities related to contractual obligations with our customers on the Alberta Clipper Pipeline related to property taxes. As a result, in 2014 and 2013, we recorded a liability for the 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, 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. For the three and six months ended June 30, 2014, we amortized through revenue \$1.7 million and \$3.5 million, 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, Line 6B 75-mile Replacement and Mainline Expansion Projects, we recorded \$17.3 million and \$40.3 million of “Allowance for equity used during construction” in our consolidated statement 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. We recorded \$12.6 million and \$33.3 million of “Allowance for equity used during construction” in our consolidated statements of income for the three and six months ended June 30, 2014, respectively, with a corresponding amount of \$33.3 million in “Property, plant and equipment” on our consolidated statement of financial position at June 30, 2014.

17. RECENT ACCOUNTING PRONOUNCEMENTS NOT YET ADOPTED

Revenues from Contracts with Customers

In May 2014, the FASB issued Accounting Standards Update No. 2014-09, which outlines a single comprehensive model for entities to use in accounting for revenue arising from contracts with customers and supersedes most current revenue recognition guidance, including industry-specific guidance. In July 2015, the FASB delayed the effective date of the new revenue standard by one year. This accounting update is effective for annual and interim periods beginning after December 15, 2017 and may be applied on either a full or modified retrospective basis. We are currently evaluating which transition approach we will apply and the impact that this pronouncement will have on our consolidated financial statements.

Going Concern Uncertainties

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

ENBRIDGE ENERGY PARTNERS, L.P.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (unaudited)

17. RECENT ACCOUNTING PRONOUNCEMENTS NOT YET ADOPTED – (continued)

Consolidation

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

Debt Issuance Costs

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

18. SUBSEQUENT EVENTS

Distribution to Partners

On July 30, 2015, the board of directors of Enbridge Management declared a distribution payable to our partners on August 14, 2015. The distribution will be paid to unitholders of record as of August 7, 2015 of our available cash of \$257.9 million at June 30, 2015, or \$0.5830 per limited partner unit. Of this distribution, \$216.1 million will be paid in cash, \$41.0 million will be distributed in i-units to our i-unitholder, Enbridge Management, and due to the i-unit distribution, \$0.8 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.

Amendment of OLP Limited Partnership Agreement

Portions of the Eastern Access and Mainline Expansion capital programs have assets that have been placed into service, which generate distributable cash flow, and assets that are still under construction, which require capital funding. These assets are held, respectively, within the Series EA and Series ME of the OLP, which are jointly funded by our General Partner at 75% and by us at 25% under joint funding arrangements. As such, each quarter we and our General Partner receive a distribution for the assets in-service and provide required capital funding contribution requirements for assets under construction in proportion to their respective Series' ownership interests.

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 distributions commencing in the quarter ended June 30, 2015 through the quarter ending 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

ENBRIDGE ENERGY PARTNERS, L.P.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (unaudited)

18. SUBSEQUENT EVENTS – (continued)

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.

Distribution to Series EA Interests

On July 30, 2015, 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 the entire distribution of \$56.5 million to us.

Distribution to Series ME Interests

On July 30, 2015, 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 the entire distribution of \$14.8 million to us.

Series 1 Preferred Unit Amended Agreement

On July 30, 2015, we amended our limited partnership agreement to extend the payment deferral of for distributions accruing for the Series 1 Preferred Units through June 30, 2018, and to allow repayment of the accumulated deferral amount in equal amounts over a twelve-quarter period beginning the quarter ending March 31, 2019. In addition, the amendment extends the current preferred distribution accrual rate until June 30, 2020, and extends the date upon which the Series 1 Preferred Units become convertible into Class A common units to June 30, 2018.

Distribution from MEP

On July 29, 2015, the board of directors of Midcoast Holdings, L.L.C., acting in its capacity as the general partner of MEP, declared a cash distribution payable to MEP's partners on August 14, 2015. The distribution will be paid to unitholders of record as of August 7, 2015, of MEP's available cash of \$16.3 million at June 30, 2015, or \$0.3525 per limited partner unit. MEP will pay \$7.5 million to their public Class A common unitholders, while \$8.8 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 29, 2015, the general partner of Midcoast Operating declared a cash distribution by Midcoast Operating payable to its partners of record as of August 7, 2015. Midcoast Operating will pay \$26.2 million to us and \$27.9 million to MEP.

On July 29, 2015, the partners of Midcoast Operating approved an amendment to Midcoast Operating's limited partnership agreement that would potentially enhance MEP's distributable cash flow, demonstrating our further support of MEP's ongoing cash distribution strategy and growth outlook. The amendment will provide a mechanism for MEP to receive increased quarterly distributions from Midcoast Operating and for us to receive reduced quarterly distributions if MEP's declared distribution exceeds its distributable cash, as that term is defined in Midcoast Operating's limited partnership agreement. 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 the Partnership's capital accounts in a liquidation scenario. The amendment to the limited partnership agreement and the support it provides to MEP's cash distribution is effective with the quarter ended June 30, 2015, and continues through and including the distribution made for the quarter ending December 31, 2017. For the second quarter of 2015, MEP did not receive an increased allocation of cash distributions from the Midcoast Operating as distributable cash flow generated in the second quarter exceeded the cash distribution amount declared for payout by 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, 2014, as filed with the Securities and Exchange Commission, or the SEC, on February 18, 2015.

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, and NGL fractionation facilities. Moreover, our Natural Gas segment also provides supply, transmission, storage and sales services to producers and wholesale customers on our natural gas gathering, transmission and customer pipelines, as well as other interconnected pipeline systems. Revenues for our Natural Gas segment are determined primarily by the volumes of natural gas gathered, compressed, treated, processed, transported and sold through our systems; the volumes of NGLs sold; and the level of natural gas, NGL and condensate prices. We also realize incremental revenue on gas purchased at the wellhead and sold to our customers. Additionally, we provide other services that are valued by our 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 each of the three and six months ended June 30, 2015 and 2014.

	For the three months ended June 30,		For the six months ended June 30,	
	2015	2014	2015	2014
	(in millions)			
Operating income (loss)				
Liquids	\$ 271.6	\$187.7	\$ 541.8	\$389.8
Natural Gas	(277.6)	(3.4)	(304.2)	8.9
Corporate, operating and administrative	(3.6)	(3.4)	(7.6)	(3.1)
Total operating income (loss)	(9.6)	180.9	230.0	395.6
Interest expense	78.0	80.2	126.3	157.1
Allowance for equity used during construction	17.3	12.6	40.3	33.3
Other income	6.0	1.2	11.9	0.4
Income (loss) before income tax expense	(64.3)	114.5	155.9	272.2
Income tax expense (benefit)	(3.8)	2.0	(1.4)	4.0
Net income (loss)	(60.5)	112.5	157.3	268.2
Less: Net income attributable to:				
Noncontrolling interest	10.0	42.4	61.3	78.7
Series 1 preferred unit distributions	22.5	22.5	45.0	45.0
Accretion of discount on Series 1 preferred units	4.1	3.7	8.0	7.3
Net income (loss) attributable to general and limited partner ownership interests in Enbridge Energy Partners, L.P.	<u>\$ (97.1)</u>	<u>\$ 43.9</u>	<u>\$ 43.0</u>	<u>\$137.2</u>

Highlights

Liquids

Our Liquids segment operating income increased \$83.9 million and \$152.0 million for the three and six months ended June 30, 2015, respectively, as compared to the same periods in 2014. Liquids segment operating income increased primarily due to additional assets placed in service and an increase in volumes on our systems. In 2014, \$2.7 billion of additional assets were placed into service on our Lakehead system, including portions of the Eastern Access, Mainline Expansion projects, and other projects. In addition, \$0.4 billion of assets related to the first tranche of phase two of the Southern Access Expansion went into service in May 2015. Average daily volumes delivered on our liquids systems increased 216,000 and 313,000 Bpd for the three and six months ended June 30, 2015 when compared to the same periods in 2014 due to increased capacity.

Natural Gas

Our Natural Gas segment operating income decreased \$274.2 million and \$313.1 million for the three and six months ended June 30, 2015, respectively, as compared to the same periods in 2014, primarily as a result of \$246.7 million in goodwill impairment that was recorded during the three months ended June 30, 2015. In addition, segment gross margin decreased due to increased non-cash, mark-to-market net losses of \$13.8 million and \$53.5 million for the three and six months ended June 30, 2015, respectively, when compared to the same periods in 2014. Furthermore, there were declines in natural gas pricing differentials and production volumes for the three and six months ended June 30, 2015, when compared to the same periods in 2014, primarily due to the current low commodity pricing environment. We expect that the current pricing environment trends will continue throughout 2015 and into 2016.

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. Some of these derivative financial instruments do not qualify for hedge accounting under the provisions of authoritative accounting guidance, which can create volatility in our earnings that can be significant. However, these fluctuations in earnings do not affect our cash flow. Cash flow is only affected when we settle the derivative instrument.

We record all derivative instruments in our consolidated financial statements at fair market value pursuant to the requirements of applicable authoritative accounting guidance. We record changes in the fair value of our derivative financial instruments that do not qualify for hedge accounting in our consolidated statements of income as 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,	
	2015	2014	2015	2014
	(in millions)			
Liquids segment:				
Non-qualified hedges	\$ (8.3)	\$ (5.3)	\$ (12.2)	\$ (7.5)
Natural Gas segment:				
Hedge ineffectiveness	—	(1.1)	(4.0)	0.6
Non-qualified hedges	(24.6)	(9.7)	(55.7)	(6.8)
Commodity derivative fair value net losses	(32.9)	(16.1)	(71.9)	(13.7)
Corporate:				
Interest rate hedge ineffectiveness	3.7	(5.3)	32.4	(11.0)
Derivative fair value net losses	<u>\$ (29.2)</u>	<u>\$ (21.4)</u>	<u>\$ (39.5)</u>	<u>\$ (24.7)</u>

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,	
	2015	2014	2015	2014
	(in millions)			
Operating Results:				
Operating revenue	\$533.0	\$474.3	\$1,088.1	\$907.0
Environmental costs, net of recoveries	(0.8)	38.2	—	43.2
Operating and administrative	116.3	117.6	246.7	226.0
Power	57.2	54.2	120.8	104.6
Depreciation and amortization	88.7	76.6	178.8	143.4
Operating expenses	261.4	286.6	546.3	517.2
Operating income	<u>\$271.6</u>	<u>\$187.7</u>	<u>\$ 541.8</u>	<u>\$389.8</u>
Operating Statistics				
Lakehead system:				
United States ⁽¹⁾	1,803	1,631	1,851	1,596
Province of Ontario ⁽¹⁾	405	457	418	449
Total Lakehead system delivery volumes ⁽¹⁾	<u>2,208</u>	<u>2,088</u>	<u>2,269</u>	<u>2,045</u>
Barrel miles (billions)	<u>150</u>	<u>144</u>	<u>307</u>	<u>279</u>
Average haul (miles)	<u>746</u>	<u>759</u>	<u>748</u>	<u>753</u>
Mid-Continent system delivery volumes ⁽¹⁾	<u>221</u>	<u>176</u>	<u>210</u>	<u>194</u>
North Dakota system:				
Trunkline ⁽¹⁾	362	311	351	277
Gathering ⁽¹⁾	3	3	2	3
Total North Dakota system delivery volumes ⁽¹⁾	<u>365</u>	<u>314</u>	<u>353</u>	<u>280</u>
Total Liquids segment delivery volumes ⁽¹⁾	<u>2,794</u>	<u>2,578</u>	<u>2,832</u>	<u>2,519</u>

⁽¹⁾ Average barrels per day in thousands.

Three months ended June 30, 2015, compared with the three months ended June 30, 2014

Operating income of our Liquids segment for the three months ended June 30, 2015, increased \$83.9 million, as compared with the same period in 2014, primarily due to the reasons discussed below.

Our Liquids segment operating revenue increased \$58.7 million for the three months ended June 30, 2015, when compared with the same period in 2014 due to the following reasons. Operating revenue increased \$64.7 million, primarily due to higher average rates as a result of placing \$2.7 billion and \$0.4 billion of additional assets into service on the Lakehead system in 2014 and through the first half of 2015, respectively. These additional assets placed into service included components of the Eastern Access, Mainline Expansion series, and other expansion projects. This amount was partially offset by a \$30.9 million decrease in rates due to qualifying volume credits related to Lakehead toll revenues. Qualifying volume credits represent a contractual obligation, which were introduced with the original Southern Access and Alberta Clipper expansions, to return a portion of the revenue to our shippers when volumes shipped exceed certain predetermined levels. Once these predetermined levels are exceeded, the expansion projects are earning their full cost-of-service and, hence, the credits are returned to the shippers through the tolls.

Additionally, operating revenue increased \$17.2 million due to increased average daily delivery volumes on our Lakehead and North Dakota systems. Volumes delivered increased by 216,000 Bpd, of which 120,000 Bpd and \$10.4 million in revenues were attributable to higher volumes on the Lakehead system as a result of additional system capacity from the aforementioned assets that were placed into service. The North Dakota system experienced an increase of 51,000 Bpd as shippers shifted volumes onto this system and away from higher cost alternatives such as transportation by rail. Finally, our operating revenue also increased by \$7.7 million due to a surcharge that went into effect on April 1, 2015, which is designed to recover half of the costs of a hydrostatic test on Line 2B that we are planning to conduct during the third quarter of 2015.

Environmental costs, net of recoveries, decreased \$39.0 million for the three months ended June 30, 2015, when compared with the same period in 2014. During the three months ended June 30, 2015 there were no cost accruals or insurance recoveries. For the same period ended 2014, there were \$35.0 million of cost accruals and no insurance recoveries.

The increase in depreciation expense of \$12.1 million for the three months ended June 30, 2015, when compared to the same period in 2014 is directly attributable to additional assets placed into service, primarily on the projects discussed above.

Six months ended June 30, 2015, compared with the six months ended June 30, 2014

Operating income of our Liquids segment for the six months ended June 30, 2015, increased \$152.0 million, as compared with the same period in 2014, primarily due to the reasons discussed below.

Operating revenue increased \$181.1 million for the six months ended June 30, 2015, when compared with the same period in 2014 due to the following reasons. Operating revenue increased \$154.2 million due to changes in rates for our Lakehead, North Dakota and Ozark systems as a result of placing \$2.7 billion and \$0.4 billion of additional assets into service on the Lakehead system in 2014 and through the first half of 2015, respectively. These additional assets placed into service included components of the Eastern Access, Mainline Expansion series, and other expansion projects. This amount was partially offset by a \$37.6 million decrease in rates due to qualifying volume credits related to Lakehead toll revenues.

Additionally, operating revenue increased \$54.2 million due to increased volumes on our Lakehead and North Dakota systems. Volumes delivered increased by 313,000 Bpd, of which 224,000 Bpd and \$37.9 million in revenues were attributable to higher volumes on the Lakehead system as a result of additional system capacity from the aforementioned assets that were placed into service. The North Dakota system experienced an increase of 73,000 Bpd as shippers shifted volumes onto this system and away from higher cost alternatives such as transportation by rail. Finally, our operating revenue also increased by \$7.7 million due to a surcharge that went into effect on April 1, 2015, which is designed to recover half of the costs of a hydrostatic test on Line 2B that we are planning to conduct during the third quarter of 2015.

Environmental costs, net of recoveries, decreased \$43.2 million for the six months ended June 30, 2015, when compared with the same period in 2014. During the six months ended June 30, 2015, there were no cost accruals or insurance recoveries. For the same period ended 2014, there were \$35.0 million of cost accruals and no insurance recoveries.

The operating and administrative expenses of our Liquids segment increased \$20.7 million for the six months ended June 30, 2015 when compared with the same period in 2014, primarily due to cost increases of \$6.5 million of workforce related costs and \$14.3 million of other operating and administrative expenses, mainly consisting of contract labor, insurance, rents and lease payments, and professional and regulatory services. These cost increases primarily resulted from the additional assets placed into service during 2014 and 2015.

Power costs increased \$16.2 million for the six months ended June 30, 2015, when compared to the same period in 2014, primarily as a result of an increase in volumes on our systems.

The increase in depreciation expense of \$35.4 million for the six months ended June 30, 2015, when compared to the same period in 2014, is directly attributable to additional assets placed into service, primarily on the projects discussed above.

Future Prospects Update for Liquids

In 2014, Enbridge announced that it is reviewing a potential restructuring plan that may involve the transfer of some of its U.S. liquids pipeline assets to us. The review of a potential transfer of Enbridge's U.S. liquids pipeline assets to us is ongoing. However, at this time market conditions do not support a large scale dropdown.

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 2015 and into 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 one 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 (in millions)	In-Service Date	Funding
Line 3 Replacement Program	\$2,600	Late 2017	EEP ⁽¹⁾
Sandpiper Project	2,600	2017	Joint ⁽²⁾
Eastern Access Projects:			
Eastern Access Upsize – Line 6B Expansion	310	First quarter 2016	Joint ⁽³⁾
U.S. Mainline Expansions:			
Chicago Area Connectivity (Line 78).	495	Fourth quarter 2015	Joint ⁽⁴⁾
Line 61 (800,000 Bpd capacity).	395	Second quarter 2015	Joint ⁽⁴⁾
Line 61 (Additional tankage).	360	Third quarter 2015 – Second quarter 2016	Joint ⁽⁴⁾
Line 61 (1,200,000 Bpd capacity).	400	2017	Joint ⁽⁴⁾
Line 67.	240	Third quarter 2015	Joint ⁽⁴⁾

⁽¹⁾ A special committee of independent directors of the Board of Enbridge Management has been established to consider a joint funding agreement with Enbridge.

⁽²⁾ Jointly funded 62.5% by us and 37.5% by Williston Basin Pipeline LLC, an affiliate of Marathon Petroleum Corp., under the North Dakota Pipeline Company Amended and Restated Limited Liability Company Agreement.

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

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

Line 3 Replacement Program

On March 3, 2014, we and Enbridge 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. Subject to regulatory and other approvals, the US L3R Program is targeted to be completed in late 2017 at an estimated cost of \$2.6 billion. While the L3R Program will not provide an increase in the overall capacity of the mainline system, it supports the safety and operational reliability of the system, enhances flexibility and will allow us and Enbridge to optimize throughput from Western Canada into Superior, Wisconsin. The L3R Program is expected to achieve an equivalent 34-inch diameter pipeline capacity of approximately 760,000 bpd.

The initial term of the Competitive Toll Settlement is 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. 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 Alberta Clipper, Eastern Access and Mainline Expansion.

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 recent 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 Project, 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 a new 24-inch diameter pipeline, in addition to adding 375,000 Bpd between Clearbrook and Superior with a 30-inch diameter pipeline. The Sandpiper project is expected to cost approximately \$2.6 billion.

We are in the process of obtaining the appropriate construction permits within the state of Minnesota for the Sandpiper Project. The permits require 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. In June 2015, the MNPUC approved the Certificate of Need and indicated that the Route Permit proceedings should be restarted. The Administrative Law Judge, or ALJ, will set the schedule for the proceedings in the third quarter of 2015. These proceedings will evaluate the preferred route and its alternatives that connect to Clearbrook, Minnesota and Superior, Wisconsin. Subject to regulatory and other approvals, particularly in the State of Minnesota, we estimate that the in-service date for the Sandpiper pipeline project will occur during 2017.

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, North Dakota Pipeline Company LLC, or 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

Since October 2011, we and Enbridge have announced multiple expansion projects that will provide 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. As part of the Light Oil Market Access Program announced in 2012, we announced an expansion project for Line 6B to increase capacity from 500,000 Bpd to 570,000 Bpd and to include: pump station modifications at Griffith, Niles and Mendon; additional modifications at the Griffith and Stockbridge terminals; and breakout tankage at Stockbridge. The expected cost of this expansion is approximately \$310 million. This further expansion of Line 6B is expected to begin service in the first quarter of 2016. This project is being 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.

U.S. Mainline Expansions

In 2012 and 2013, we announced further expansion projects for our mainline pipeline system including: (1) expanding our existing 36-inch diameter Alberta Clipper pipeline, or Line 67; (2) expanding our existing 42-inch diameter Southern Access pipeline, or Line 61; and (3) expanding by constructing Line 78, a twin of the Spearhead North pipeline, or Line 62.

The current scope of the Line 67 pipeline expansion between Neche, North Dakota and the Superior, Wisconsin Terminal consists of two phases. The initial phase included increasing capacity from 450,000 Bpd to 570,000 Bpd at an estimated capital cost of \$220 million. The second phase of the expansion will increase capacity from 570,000 Bpd to 800,000 Bpd at an estimated capital cost of approximately \$240 million. The initial phase was completed in the third quarter of 2014 and the second phase was completed in July 2015. Both phases of the Line 67 pipeline expansion required only the addition of pumping horsepower, with no pipeline construction, and are subject to regulatory and other approvals, including an amendment to the current Presidential border crossing permit to allow for the operation of the Line 67 pipeline at its currently-planned operating capacity of 800,000 Bpd. We continue to work with regulatory authorities; however, 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.

In November 2014, several environmental and Native American groups filed a complaint in the United States District Court in Minnesota against the United States Department of State, or DOS. The complaint alleges, among other things, that the DOS is in violation of the National Environmental Policy Act by acquiescing in Enbridge's use of permitted cross border capacity on other lines to achieve the transportation of amounts in excess of the current permitted capacity of Alberta Clipper pending review and approval of Enbridge's application to the DOS to

increase the permitted cross border capacity of Alberta Clipper. Enbridge has intervened in the case. A decision at the trial level is not expected before the fourth quarter of 2015.

The current scope of the Southern Access expansion, or Line 61 expansion, between Superior, Wisconsin and Flanagan, Illinois also consists of two phases. The initial phase of the Line 61 expansion was completed in August 2014 and increased capacity between the Superior Terminal and the Flanagan Terminal near Pontiac, Illinois from 400,000 Bpd to 560,000 Bpd. The second phase of the Line 61 expansion will further expand the pipeline and add crude oil tankage at new and existing sites. The pipeline expansion will be split into two tranches. The first tranche expands the pipeline capacity to 800,000 Bpd at a cost of approximately \$395 million and went into service in May of 2015. Additional tankage is expected to cost approximately \$360 million and is expected to be completed on various dates beginning in the third quarter of 2015 through the second quarter of 2016. On April 17, 2015, the OLP filed an amended tariff with the FERC to provide shippers with optional in-transit merchant storage service. After discussions with the Canadian Association of Petroleum Producers and other shippers, on May 4, 2015, we agreed to conditionally withdraw this service in order to engage shippers in further discussions regarding the appropriate utilization and compensation for the tank facilities. Those discussions have concluded and the tank facilities will be placed into operational use on the Lakehead system.

The second tranche of the Southern Access expansion will expand the pipeline capacity to 1,200,000 Bpd at a cost of approximately \$400 million. Management, in conjunction with shippers, decided to delay the in-service date of the final tranche of the Line 61 expansion to align more closely with the currently anticipated in-service date for the Sandpiper project in 2017, which will drive the need for additional downstream capacity.

Furthermore, as part of the Light Oil Market Access Program announced in 2012, the capacity on our Lakehead System between Flanagan, Illinois, and Griffith, Indiana will be expanded by constructing Line 78, a 79-mile, 36-inch diameter twin of the Spearhead North pipeline, or Line 62, with an initial capacity of 570,000 Bpd, at an estimated cost of \$495 million. Subject to regulatory and other approvals, the expansion is expected to begin service in the fourth quarter of 2015.

These projects, collectively referred to as the U.S. Mainline Expansion projects, will be undertaken on a cost-of-service basis. Furthermore, these projects are jointly funded 75% by our General Partner and at 25% by us, under the Mainline Expansion Joint Funding Agreement, which parallels the Eastern Access Joint Funding Agreement. Within one year of the in-service date, scheduled for 2017, we will have the option to increase our economic interest held at that time by up to 15% at cost.

Canadian Eastern Access and Mainline Expansion Projects

The Eastern Access Projects and U.S. Mainline Expansions projects complement Enbridge's strategic initiative of expanding access to new markets in North America for growing production from western Canada and the Bakken Formation.

Since October 2011, Enbridge also announced several complementary Eastern Access and Mainline Expansion Projects. These projects include: (1) reversal of Enbridge's Line 9A in western Ontario to permit crude oil movements eastbound from Sarnia as far as Westover, Ontario, which was completed and placed into service in August 2013; (2) construction of a 35-mile pipeline adjacent to Enbridge's Toledo Pipeline, originating at our Line 6B in Michigan to serve refineries in Michigan and Ohio, which was completed and placed into service in May 2013; (3) reversal of Enbridge's Line 9B from Westover, Ontario to Montreal, Quebec to serve refineries in Quebec; (4) an expansion of Enbridge's Line 9 to provide additional delivery capacity within Ontario and Quebec; (5) expansions to add horsepower on existing lines on the Enbridge Mainline system from western Canada to the U.S. border, where the first phase of the expansion was completed in August 2014; and (6) modifications to existing terminal facilities on the Enbridge Mainline system, comprised of upgrading existing booster pumps, additional booster pumps and new tank line connections in order to accommodate additional oil volumes and enhance operational flexibility. The outstanding projects have various targeted in-service dates throughout 2015. The Line 9B reversal and Line 9 capacity expansion projects were approved by the Canadian National Energy Board, or NEB, in March 2014 subject to 30 conditions. In October 2014, the NEB requested additional information regarding one of the conditions imposed on the Line 9B reversal and Line 9 expansion project. On October 23, 2014, Enbridge responded to the NEB describing Enbridge's rigorous approach to risk management and isolation valve placement. On February 6, 2015, the NEB approved Conditions 16 and 18, the two conditions in the NEB's order requiring approval, and Enbridge filed for the Leave to Open, or LTO, which is a prerequisite to allowing the operation of the project. In its February approval, the NEB also imposed additional obligations on Enbridge that direct it to take a "life-cycle" approach to water crossings and valves, requiring Enbridge to perform ongoing analysis to ensure optimal protection of the area's water resources. On June 18, 2015, the NEB approved the LTO application and issued a separate order imposing further conditions requiring

Enbridge to perform hydrostatic tests of selected segments of the pipeline. Enbridge filed its hydrostatic test plan with the NEB on July 23, 2015, which was approved on July 27, 2015. Pending detailed engineering to confirm scope and timelines and fulfillment of permitting requirements, Enbridge expects the hydrostatic testing to be completed before the end of 2015. The line is expected to be placed into service following completion of the NEB's review of the hydrostatic testing.

Enbridge Market Extensions

One of our key strengths is our relationship with Enbridge. In 2014, Enbridge announced the completion of two major U.S. Gulf Coast market access pipeline projects, the Flanagan South Pipeline and Seaway Crude Pipeline, which are expected to pull more volume through our pipelines and may lead to further expansions of our Lakehead pipeline system. In 2012 Enbridge announced the Southern Access Extension, which, along with the reversal of Line 9A and 9B, will support the increasing supply of light oil from Canada and the Bakken into Patoka, Illinois.

Southern Access Extension

The Southern Access Extension project involves the construction of a 165-mile, 24-inch diameter crude oil pipeline from Flanagan to Patoka, Illinois, with an initial capacity of 300,000 Bpd, as well as additional tankage and two new pump stations. The project is expected to be placed into service in late 2015. Lincoln Pipeline LLC, or Lincoln, an affiliate of MPC, has a 35% equity interest in the project and will make cash contributions in accordance with the Southern Access Extension's spend profile in proportion to its 35% interest.

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,	
	2015	2014	2015	2014
	(in millions)			
Operating revenues	\$ 780.1	\$ 1,396.8	\$ 1,653.6	\$ 3,043.7
Commodity costs	670.6	1,259.8	1,449.7	2,748.5
Operating and administrative	87.3	103.6	170.0	212.5
Goodwill impairment.	246.7	—	246.7	—
Asset impairment charges.	12.3	—	12.3	—
Depreciation and amortization.	40.8	36.8	79.1	73.8
Operating expenses	1,057.7	1,400.2	1,957.8	3,034.8
Operating income (loss)	(277.6)	(3.4)	(304.2)	8.9
Other income	5.9	2.3	11.6	1.0
Net income (loss)	\$ (271.7)	\$ (1.1)	\$ (292.6)	\$ 9.9
Operating Statistics (MMBtu/d)				
East Texas	968,000	1,029,000	988,000	1,000,000
Anadarko.	794,000	819,000	811,000	822,000
North Texas	274,000	300,000	281,000	286,000
Total.	2,036,000	2,148,000	2,080,000	2,108,000
NGL Production (Bpd)	81,056	83,480	81,051	82,196

Three months ended June 30, 2015, compared with the three months ended June 30, 2014

The operating loss of our Natural Gas business for the three months ended June 30, 2015, increased \$274.2 million as compared with the same period in 2014, primarily as a result of a \$246.7 million goodwill impairment charge and a non-cash impairment charge of \$12.3 million from an expected loss on the disposal of our non-core, held-for-sale assets that were recorded during the three months ended June 30, 2015. We performed a goodwill impairment analysis after we learned from customers during the second quarter of 2015 that reductions in drilling will be prolonged in the producing basins in which we operate due to the continued low commodity price environment. As a result of this analysis, we determined that \$246.7 million in goodwill was impaired. In the longer term we expect our performance to strengthen although the pace and magnitude of improvement is less than we previously forecast given the forecast protracted recovery in commodity prices and related supply and demand

fundamentals. In addition, segment gross margin decreased \$27.5 million for the three months ended June 30, 2015, as compared with the same period in 2014. Partially offsetting the segment gross margin decrease were decreased operating and administrative costs due to cost reductions undertaken by management.

Segment gross margin experienced a net decrease of \$13.8 million due to non-cash, mark-to-market losses of \$24.6 million and \$10.8 million for the three months ended June 30, 2015 and June 30, 2014, respectively. These losses are primarily related to the reversal of previously recognized unrealized market-to-market gains as the underlying transactions were settled.

Segment gross margin decreased by approximately \$9.3 million for the three months ended June 30, 2015 as compared to the same period in 2014, due to reduced production volumes. The average daily volumes of our major systems for the three months ended June 30, 2015, decreased by 112,000 MMBtu/d, or 5%, when compared to the same period in 2014. The average NGL production for the three months ended June 30, 2015, decreased by 2,424 Bpd, or 3%, when compared to the same period in 2014. The decrease in natural gas and NGL volumes was primarily attributable to the continued low commodity price environment for natural gas, NGLs, and condensate, which has resulted in reductions in drilling activity from producers in the areas we operate.

Segment gross margin decreased \$6.2 million for the three months ended June 30, 2015, as compared with the same period in 2014, due to decreased margins from lower commodity prices, net of hedges, related to contracts where we were paid in commodities for our services.

Operating and administrative costs decreased \$16.3 million for the three months ended June 30, 2015, compared to the same period in 2014, primarily due to work force reductions and other management cost reduction efforts, which resulted in a decrease in contract labor as well as other related cost benefits.

Depreciation and amortization expense for our Natural Gas segment increased \$4.0 million, for the three months ended June 30, 2015, compared with the same period of 2014, due to additional assets that were put in service.

Other income increased \$3.6 million for the three months ended June 30, 2015, compared to the same period in 2014 as a result of increases in equity earnings on our investment in the Texas Express NGL system primarily from increases in demand payments from Texas Express shippers.

Six months ended June 30, 2015, compared with the six months ended June 30, 2014

The operating income of our Natural Gas business for the six months ended June 30, 2015, decreased \$313.1 million, as compared with the same period in 2014, primarily due to the \$246.7 million goodwill impairment charge recorded during 2015 and a non-cash impairment charge of \$12.3 million from an expected loss on disposal of our non-core, held-for-sale assets that were recorded during the six months ended June 30, 2015, as discussed above. In addition, segment gross margin, decreased \$91.3 million for the six months ended June 30, 2015, as compared with the same period in 2014.

Segment gross margin experienced a net decrease of \$53.5 million due to non-cash, mark-to-market losses of \$59.7 million and \$6.2 million for the six months ended June 30, 2015 and June 30, 2014, respectively. These losses are primarily related to the reversal of previously recognized unrealized market-to-market gains as the underlying transactions were settled.

Our segment gross margin was also impacted by decreased margins within our gas marketing function due to price differentials between market centers of approximately \$31.0 million for the six months ended June 30, 2015, when compared to the same period in 2014. During the first quarter of 2014, we benefited from the difference between market centers in the Mid-Continent supply areas and market area in the Midwest which arose due to higher than usual demand from winter weather conditions in the Midwest.

Our segment gross margin decreased \$6.6 million for the six months ended June 30, 2015, compared with the same period in 2014 in our Natural Gas segment due to lower storage margins as a result of sale of liquids product inventory at prevailing market prices relative to the cost of product inventory. Our segment gross margin also decreased \$2.0 million for the six months ended June 30, 2015, when compared to the same period of 2014, for non-cash charges to decrease the cost basis of our natural gas inventory to net realizable value. Since we hedge our storage positions financially, these charges are recovered when the physical natural gas inventory is sold or the financial hedges are realized.

Segment gross margin decreased \$3.1 million, compared to the same period in 2014, due to reduced production volumes. The average daily volumes of our major systems for the six months ended June 30, 2015, decreased by approximately 28,000 MMBtu/d, or 1%, when compared to the same period in 2014. The average NGL production for the six months ended June 30, 2015, decreased by 1,145 Bpd, or 1%, when compared to the same period in 2014. The decrease in natural gas and NGL volumes was primarily attributable to commodity price declines for natural gas, NGLs, and condensate declining during 2015, which has resulted in reductions in drilling activity from producers in the areas we operate.

Decreases in segment gross margin were offset by an increase of approximately \$4.4 million compared to the same period in 2014, due to increases in service fees.

Operating and administrative costs of our Natural Gas segment decreased \$42.5 million for the six months ended June 30, 2015, compared to the same period in 2014, primarily due to work force reductions and other management cost reduction efforts, which resulted in a decrease in contract labor as well as other related cost benefits.

Depreciation and amortization expense for our Natural Gas segment increased \$5.3 million, for the six months ended June 30, 2015, compared with the same period of 2014, due to additional assets that were put in service.

Other income increased \$10.6 million for the six months ended June 30, 2015, compared to the same period in 2014 as a result of increases in equity earnings on our investment in the Texas Express NGL system primarily from increases in demand payments from Texas Express shippers.

Future Prospects for Natural Gas

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

Impact of Commodity Prices

Demand for our midstream services primarily depends upon the supply of natural gas and associated natural gas from crude oil development and the drilling rate for new wells. Demand for these services depends on overall economic conditions and commodity prices. Commodity prices for natural gas, NGLs, condensate and crude oil began declining during the fourth quarter of 2014, and the low commodity prices have continued throughout the first half of 2015. As a result, we expect reductions in drilling activity by producers in the areas where we operate to continue until prices improve.

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

Expansion Projects

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

Beckville Cryogenic Processing Plant

In May 2015, we placed into service a cryogenic natural gas processing plant near Beckville in Panola County, Texas, which we refer to as the Beckville Processing Plant. This plant serves existing and prospective customers pursuing production in the Cotton Valley formation, which is comprised of approximately ten counties in East Texas and has been a steady producer of natural gas for decades, as well as the Eaglebine developments. Production from the Cotton Valley formation typically contains two to three gallons of NGLs per Mcf of natural gas. The region currently produces approximately 2.2 billion cubic feet per day, or Bcf/d, of natural gas with 73,000 Bpd of associated NGLs. Until recently, the primary exploitation method in the Cotton Valley formation has been vertical

wells. Lower horizontal drilling costs, coupled with the latest fracturing technology, have brought significant interest back to this area. Economics associated with horizontal wells in the Cotton Valley formation compare favorably to other rich natural gas plays, which has encouraged producers to increase drilling activity in the region. Our Beckville processing plant is capable of processing approximately 150 MMcf/d of natural gas and producing approximately 8,500 Bpd of NGLs to accommodate the additional liquids-rich natural gas being developed within this geographical area in which our East Texas system operates. Related NGL takeaway infrastructure connecting the Beckville plant to third party NGL transportation systems was also constructed. This project cost approximately \$165.0 million.

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

Eaglebine Developments

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

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

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

Corporate

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

	<u>For the three months ended June 30,</u>		<u>For the six months ended June 30,</u>	
	<u>2015</u>	<u>2014</u>	<u>2015</u>	<u>2014</u>
	(in millions)			
Operating Results:				
Operating and administrative expenses	\$ 3.6	\$ 3.4	\$ 7.6	\$ 3.1
Operating loss	(3.6)	(3.4)	(7.6)	(3.1)
Interest expense, net	78.0	80.2	126.3	157.1
Allowance for equity used during construction	17.3	12.6	40.3	33.3
Other income (expense)	0.1	(1.1)	0.3	(0.6)
Income tax expense (benefit)	(3.8)	2.0	(1.4)	4.0
Net loss	(60.4)	(74.1)	(91.9)	(131.5)

Three months ended June 30, 2015, compared with three months ended June 30, 2014

The \$13.7 million decrease in our net loss for the three months ended June 30, 2015, as compared to the same period in 2014 was primarily attributable to an increase of allowance for equity used during construction and a decrease in income taxes.

Allowance for equity used during construction increased \$4.7 million for the three months ended June 30, 2015, compared with the corresponding period in 2014, primarily related to construction on our Mainline Expansion projects.

Our income tax benefit was \$3.8 million for the three months ended June 30, 2015 compared to an income tax expense of \$2.0 million for the three months ended June 30, 2014. The \$5.8 million reduction in income tax

expense was primarily due to a \$5.4 million tax benefit from a reduction in deferred income tax payable. This reduction is the result of a reduction in the Texas franchise tax rate from the recently-enacted Texas House Bill 32.

Six months ended June 30, 2015, compared with six months ended June 30, 2014

The results for corporate activities for the six months ended June 30, 2015, compared to the same period in 2014, changed for the same reasons as noted in the three month analysis above in addition to the factors discussed below.

Interest expense decreased \$30.8 million for the six months ended June 30, 2015, as compared to the same period in 2014 primarily due to charges to interest expense from ineffectiveness on hedging instruments.

LIQUIDITY AND CAPITAL RESOURCES

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 senior unsecured revolving credit facility, which we refer to as the Credit Facility, and our \$650.0 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. In addition, we have a credit agreement with EUS, or the EUS 364-day Credit Facility, which provides an additional \$750.0 million in liquidity. 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.

On July 2, 2015, we amended our 364-Day Credit Facility to extend the revolving credit termination date from July 3, 2015 to July 1, 2016. We further amended the 364-Day Credit Facility to decrease the aggregate commitments from \$650.0 million to \$525.0 million.

As set forth in the following table, we had approximately \$1.5 billion of liquidity available to us at June 30, 2015, to meet our ongoing operational, investment and financing needs, as well as the funding requirements associated with the environmental remediation costs resulting from the crude oil release on Line 6B.

	<u>EEP</u>	<u>MEP</u>
	(in millions)	
Cash and cash equivalents	\$ 82.3	\$ 27.5
Total credit available under EEP's Credit Facilities ⁽¹⁾	2,625.0	—
Total credit available under the EUS 364-day Credit Facility	750.0	—
Total credit available under MEP's Credit Agreement	—	850.0
Less: Amounts outstanding under the Credit Facilities	(810.0)	—
Amounts outstanding under the EUS 364-day Credit Facility	—	—
Amounts outstanding under MEP's Credit Agreement	—	(410.0)
Principal amount of commercial paper issuances	(1,257.6)	—
Letters of credit outstanding	(317.2)	—
Total	<u>\$ 1,072.5</u>	<u>\$ 467.5</u>

⁽¹⁾ On July 2, 2015, we had an amendment to our 364-day Credit Facility. After the amendment on a pro-forma basis our total credit available under our Credit Facilities is \$2,500.0 million, and the total amount available under the Credit Facilities and the EUS 364-day Credit Facility, less amounts outstanding, is \$865.2 million.

General

Our primary operating cash requirements consist of normal operating expenses, maintenance capital expenditures, 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 on 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 emphasizes developing and expanding our existing Liquids and Natural Gas businesses through organic growth and targeted acquisitions. We expect to initially fund our long-term cash requirements for expansion projects and acquisitions, as well as retire our maturing and callable debt, first from operating cash flows and then from issuances of commercial paper and borrowings on our Credit Facilities. We expect to obtain permanent financing as needed through the issuance of additional equity and debt securities, which we will use to repay amounts initially drawn to fund these activities, although there can be no assurance that such financings will be available on favorable terms, if at all. In addition, we intend to sell additional interests in Midcoast Operating entity to MEP to raise capital over the course of the next several years. Although this is our intent, there is no assurance that any transactions will occur as they are subject to, among other things, obtaining agreement from MEP and its board of directors around the commercial terms of such a sale. When we have attractive growth opportunities in excess of our own capital raising capabilities, the General Partner has 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 the General Partner, but there can be no assurance that this funding can be obtained.

As of June 30, 2015, we had a working capital deficit of approximately \$0.9 billion and approximately \$1.5 billion of liquidity to meet our ongoing operational, investment and financing needs as shown above, as well as the funding requirements associated with the environmental remediation costs resulting from the crude oil releases on Line 6B.

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. 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. In February 2015, we filed with the SEC a new shelf registration statement, or the 2015 Shelf, on Form S-3 that replaced our prior shelf registration statement which expired in December 2014. The 2015 Shelf allows us to issue an unlimited amount of equity and debt securities in underwritten public offerings.

Issuance of Class A Common Units

In March 2015, we sold 8 million Class A common units in an underwritten public offering pursuant to the 2015 Shelf for net proceeds of \$288.8 million. The following table presents the net proceeds from our Class A common unit issuances for the current year. The proceeds from the March 2015 offering were used to fund a portion of our capital expansion projects and for general partnership purposes.

<u>2015 Issuance Date</u>	<u>Number of Class A common units Issued</u>	<u>Offering Price per Class A common unit</u>	<u>Net Proceeds to the Partnership⁽¹⁾</u>	<u>General Partner Contribution⁽²⁾</u>	<u>Net Proceeds Including General Partner Contribution</u>
		(in millions, except units and per unit amount)			
March	8,000,000	\$36.70	\$288.8	\$6.0	\$294.8

⁽¹⁾ Net of underwriters' fees and discounts, commissions and issuance expenses.

⁽²⁾ Contributions made by the General Partner to maintain its 2% general partner interest.

Series 1 Preferred Unit Amended Agreement

On July 30, 2015, we amended our limited partnership agreement to extend the payment deferral of for distributions accruing for the Series 1 Preferred Units through June 30, 2018, and to allow repayment of the accumulated deferral amount in equal amounts over a twelve-quarter period beginning the quarter ending March 31, 2019. In addition, the amendment extends the current preferred distribution accrual rate until June 30, 2020, and extends the date upon which the Series 1 Preferred Units become convertible into Class A common units to June 30, 2018.

Available Credit

Our two primary sources of liquidity are provided by our commercial paper program and our Credit Facilities. We have a \$1.5 billion commercial paper program that is supported by our Credit Facilities, which we access 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, 2015, we had approximately \$990.2 million in available credit under the terms of our Credit Facilities. For a description of our commercial paper program and our Credit Facilities, see Note 8. *Debt*, in Item 1, *Financial Statements*.

Joint Funding Arrangements

In order to obtain the required capital to expand our various pipeline systems, we have determined that the required funding would challenge our ability to efficiently raise capital. Accordingly, we have explored numerous options and determined that several joint funding arrangements would provide the best source of available capital to fund the expansion projects.

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. 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, scheduled for early 2016, we have the option to increase our economic interest by up to 15 percentage points.

Our General Partner made equity contributions totaling \$98.3 million and \$360.8 million to the OLP during the six months ended June 30, 2015 and 2014, 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. 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, currently scheduled for 2016, 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 \$360.7 million and \$177.7 million to the OLP for the six months ended June 30, 2015 and 2014, respectively, to fund its equity portion of the construction costs associated with the Mainline Expansion Projects.

Amendment of OLP Limited Partnership Agreement

Portions of the Eastern Access and Mainline Expansion capital programs have assets that have been placed into service, which generate distributable cash flow, and assets that are still under construction, which require capital funding. These assets are held, respectively, within the Series EA and Series ME of the OLP, which are jointly funded by our General Partner at 75% and by us at 25% under joint funding arrangements. As such, each quarter we and our General Partner receive a distribution for the assets in-service and provide required capital funding contribution requirements for assets under construction in proportion to their respective Series' ownership interests.

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 distributions commencing in the quarter ended June 30, 2015 through the quarter ending 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.

Financing Transactions with Affiliates

EUS 364-day Credit Facility

On March 9, 2015, we entered into the EUS Credit Facility. 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 March 7, 2016 and including the option to term the revolving loan for a period of 364-days following the termination date, the credit facility becomes non-revolving thus extending the term to March 6, 2017. There is no outstanding balance as of June 30, 2015 under the EUS 364-day Credit Facility.

The commitment under the EUS 364-day Credit Facility may be permanently reduced by EUS, from time to time, by up to an amount equal to the net cash proceeds to us from the sale by us of (1) debt or equity securities in a registered public offering, or (2) limited partnership interests in Midcoast Operating to MEP.

Cash Requirements

Capital Spending

We expect to make additional expenditures during the remainder of the year for the acquisition and construction of natural gas processing and crude oil transportation infrastructure. In 2015, we expect to spend approximately \$1.3 billion on expansion capital and other projects associated with our liquids and natural gas systems with the expectation of realizing additional cash flows as projects are completed and placed into service. Of this amount, we expect to spend approximately \$105 million on maintenance capital activities. We expect to receive funding of approximately \$1 billion from our General Partner based on our joint funding arrangement for the Eastern Access Projects, Mainline Expansion Projects and Line 3 Replacement Project. Furthermore, we expect to receive funding of approximately \$130 million from MPC based on joint funding arrangement on the Sandpiper Project. We made capital expenditures of approximately \$1 billion for the six months ended June 30, 2015, including \$41.6 million on maintenance capital activities and \$502.6 million of expenditures that were financed by contributions from our General Partner and MPC via joint funding arrangements. In addition, we incurred \$2.5 million in net contributions to fund our joint ventures. At June 30, 2015, we had approximately \$1.0 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 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 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. 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 estimate our capital expenditures based upon our strategic operating and growth plans, which are also dependent upon our ability to produce or otherwise obtain the financing necessary to accomplish our growth

objectives. The following table sets forth our estimated maintenance and expansion capital expenditures we expect to make for the full year ending December 31, 2015. Although we anticipate making these expenditures in 2015, these estimates may change due to factors beyond our control, including weather-related issues, construction timing, 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
	(in millions)
<i>Liquids Projects</i>	
Eastern Access Projects	\$ 300
U.S. Mainline Expansions	910
Sandpiper	345
Line 3 Replacement	185
Liquids Integrity Program	260
Expansion Capital	210
Maintenance Capital Expenditures	60
	<u>2,270</u>
<i>Less joint funding from:</i>	
General Partner	1,000
Third parties	130
Liquids Total	<u>\$1,140</u>
<i>Natural Gas Projects</i>	
Beckville Cryogenic Processing Plant	\$ 60
Eaglebine Developments	135
Expansion Capital	100
Maintenance Capital Expenditures	45
	<u>340</u>
<i>Less joint funding from:</i>	
MEP	175
Natural Gas Total	<u>\$ 165</u>
TOTAL	<u><u>1,305</u></u>

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.

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 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. Expenditure levels have continued to increase as pipelines age and require higher levels of inspection, maintenance and capital replacement. We also anticipate that maintenance capital will continue to 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.

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.

Environmental

Lakehead Line 6B Crude Oil Release

During the six months ended June 30, 2015, our cash flows were affected by the approximate \$20.1 million we paid for the environmental remediation, restoration and cleanup activities resulting from the crude oil releases 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. For more information, please refer to Note 11. *Commitments and Contingencies* of our consolidated financial statements.

Derivative Activities

We use derivative financial instruments (i.e., futures, forwards, swaps, options and other financial instruments with similar characteristics) to manage the risks associated with market fluctuations in commodity prices and interest rates and 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.

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, 2015 for each of the indicated calendar years:

	Notional	2015	2016	2017	2018	2019 & Thereafter	Total ⁽³⁾
		(in millions)					
Swaps							
Natural gas ⁽¹⁾	110,535,374	\$ 0.7	\$ 0.4	\$ 0.2	\$ —	\$—	\$ 1.3
NGL ⁽²⁾	5,423,600	13.4	7.4	(1.2)	—	—	19.6
Crude Oil ⁽²⁾	3,745,284	17.5	0.8	—	—	—	18.3
Options							
Natural gas – puts purchased ⁽¹⁾	3,671,000	2.1	1.2	—	—	—	3.3
Natural gas – puts written ⁽¹⁾	3,671,000	(2.1)	(1.2)	—	—	—	(3.3)
Natural gas – calls purchased ⁽¹⁾	2,291,000	—	0.1	—	—	—	0.1
Natural gas – calls written ⁽¹⁾	2,291,000	—	(0.1)	—	—	—	(0.1)
NGL – puts purchased ⁽²⁾	4,543,200	20.6	38.9	0.8	—	—	60.3
NGL – puts written ⁽²⁾	137,500	(1.2)	(1.1)	—	—	—	(2.3)
NGL – calls purchased ⁽²⁾	91,500	—	0.1	—	—	—	0.1
NGL – calls written ⁽²⁾	4,129,200	(0.1)	(2.8)	(0.6)	—	—	(3.5)
Crude Oil – puts purchased ⁽²⁾	1,720,700	7.9	12.9	4.3	—	—	25.1
Crude Oil – calls written ⁽²⁾	1,720,700	—	(0.8)	(2.7)	—	—	(3.5)
Forward contracts							
Natural gas ⁽¹⁾	272,300,437	0.9	0.8	0.2	0.1	—	2.0
NGL ⁽²⁾	22,464,309	8.8	1.9	—	—	—	10.7
Crude Oil ⁽²⁾	1,082,027	(0.4)	0.1	—	—	—	(0.3)
Totals		<u>\$68.1</u>	<u>\$58.6</u>	<u>\$ 1.0</u>	<u>\$0.1</u>	<u>\$—</u>	<u>\$127.8</u>

⁽¹⁾ Notional amounts for natural gas are recorded in MMBtu.

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

⁽³⁾ Fair values exclude credit adjustment losses of approximately \$0.2 million at June 30, 2015 as well as cash collateral received.

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, 2015 for each of the indicated calendar years:

	Notional	2015	2016	2017	2018	2019	Total ⁽¹⁾
		(in millions)					
Interest Rate Derivatives							
Interest Rate Swaps:							
Floating to Fixed	\$2,020	\$ (2.9)	\$ (7.5)	\$ (5.8)	\$(3.8)	\$(0.7)	\$ (20.7)
Pre-issuance hedges	\$2,350	(254.6)	(57.1)	(25.6)	3.7	—	(333.6)
		<u>\$(257.5)</u>	<u>\$(64.6)</u>	<u>\$(31.4)</u>	<u>\$(0.1)</u>	<u>\$(0.7)</u>	<u>\$(354.3)</u>

⁽¹⁾ Fair values exclude credit valuation adjustment gains of approximately \$1.7 million at June 30, 2015.

Cash Flow Analysis

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

	For the six months ended June 30,		Variance 2015 vs. 2014
	2015	2014	Increase (Decrease)
	(in millions)		
Total cash provided by (used in):			
Operating activities	\$ 646.9	\$ 359.6	\$ 287.3
Investing activities	(996.3)	(1,287.0)	290.7
Financing activities	261.3	1,112.5	(851.2)
Net increase (decrease) in cash and cash equivalents	(88.1)	185.1	(273.2)
Cash and cash equivalents at beginning of year	197.9	164.8	33.1
Cash and cash equivalents at end of period	<u>\$ 109.8</u>	<u>\$ 349.9</u>	<u>\$(240.1)</u>

Operating Activities

Net cash provided by our operating activities increased \$287.3 million for the six months ended June 30, 2015, compared to the same period in 2014. Net income decreased \$110.9 million for the six months ended June 30, 2015, when compared to the same period ended in 2014. Our net income was negatively impacted by \$258.4 million of increases in non-cash items, primarily due to \$246.7 million of goodwill impairment. The change in net cash provided by our operating activities also increased due to an increase in our working capital accounts of \$129.2 million as shown in the following table and discussed below:

	For the six months ended June 30,		Variance 2015 vs. 2014
	2015	2014	
	(in millions)		
Changes in operating assets and liabilities, net of acquisitions:			
Receivables, trade and other	\$ 45.7	\$ 9.1	\$ 36.6
Due from General Partner and affiliates	(62.7)	5.3	(68.0)
Accrued receivables	158.9	51.8	107.1
Inventory	(1.3)	(75.7)	74.4
Current and long-term other assets	(33.0)	(16.5)	(16.5)
Due to General Partner and affiliates	66.9	(6.0)	72.9
Accounts payable and other	(56.6)	(63.8)	7.2
Environmental liabilities	(21.6)	(62.9)	41.3
Accrued purchases	(114.8)	(3.2)	(111.6)
Interest payable	1.2	1.4	(0.2)
Property and other taxes payable	(15.6)	(1.6)	(14.0)
Net change in working capital accounts	<u>\$ (32.9)</u>	<u>\$(162.1)</u>	<u>\$ 129.2</u>

The changes in our operating assets and liabilities, net of acquisitions, as presented in our consolidated statements of cash flow for the six months ended June 30, 2015 and 2014, are primarily the result of general timing differences for cash receipts and payment associated with our third-party accounts. The main items affecting our cash flows from changes in operating assets and liabilities include the following:

- The change in accrued receivables of \$107.1 million for the six months ended June 30, 2015 was primarily the result of collecting receivables at higher prices relative to current receivables recorded, offset by decreased sales of our receivables per our Receivables Agreement. For the six months ended June 30, 2014, our receivables decreased due to reduced prices and volumes coupled with increased sales of receivables under our Receivables Agreement;
- The decline in accrued purchases of \$111.6 million for the six months ended June 30, 2015 was primarily the result of lower prices of natural gas and NGLs combined with lower volumes purchased. For the six months ended June 30, 2014, payments and accruals were relatively flat;

- The change in working capital from inventory was an increase of \$74.4 million for the six months ended June 30, 2015. The change in inventory for the six months ended June 30, 2015, was primarily the result of lower prices of natural gas and NGLs offset by the seasonal increase of volumes. For the six months ended June 30, 2014, our inventory increased due to increases in both volumes and prices of natural gas and NGLs; and
- The decrease in environmental liabilities of \$41.3 million for the six months ended June 30, 2015 compared to the six months ended June 30, 2014 was primarily the result of decreased payments associated with the accrual for the Line 6B crude oil release.

Investing Activities

Net cash used in our investing activities during the six months ended June 30, 2015 decreased by \$290.7 million compared to the same period in 2014 primarily due to decreased additions to property, plant and equipment, net of construction payables of \$314.1 million in 2015 related to reduced payments on our construction payables and decreased spending on pipeline integrity costs when compared to the same period in 2014. This increase was offset by increased asset acquisitions of 85.0 million due to the acquisition of NGR's midstream assets.

Financing Activities

Net cash provided by our financing activities decreased \$851.2 million for the six months ended June 30, 2015 compared to the same period in 2014 primarily due to the following:

- Repayments of the remaining outstanding balance of \$306.0 million to the General Partner for the A1 Loan on January 2, 2015, compared to repayments on the A1 Loan of \$6.0 million for the six months ended June 30, 2014;
- Decreased net borrowings on the commercial paper program of \$120.1 million;
- Decreased capital contributions from noncontrolling interest of \$110.3 million for ownership interests in the Mainline Expansion Projects, Eastern Access Projects and Sandpiper Project;
- Increased distributions to our limited partners of \$46.9 million and distributions to noncontrolling interest of \$128.7 million due to phases of the Eastern Access Project and Mainline Expansion Project being placed into service; and
- Increased net repayments under our credit facility of \$440.0 million.

The decreases above were offset by net proceeds from our Class A unit issuance, including our General Partner's contributions, of \$294.8 million in March 2015. We had no similar issuances in 2014.

REGULATORY MATTERS

FERC Transportation Tariffs

Lakehead System

On February 27, 2015, we filed our annual rate adjustment with the FERC for the Facilities Surcharge Mechanism, or FSM, component of the Lakehead system with rates effective April 1, 2015. The FSM allows Lakehead to recover 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 2015 and an adjustment for the difference between estimated and actual costs and throughput for the prior year. The surcharge is applicable to all volumes entering our system from the effective date of the tariff, which we recognize as revenue when the barrels are delivered, typically a period of approximately 30 days from the date shipped.

This tariff filing decreased our transportation rate for heavy crude oil movements from the Canadian border to the Chicago, Illinois area by approximately \$0.10 per barrel, to approximately \$2.39 per barrel. The tariff filing also decreased our transportation rate for light crude oil movements from the Canadian border to the Chicago, Illinois area by approximately \$0.08 per barrel, to approximately \$1.98 per barrel. These decreases were primarily the result of an increase in forecasted 2015 throughput and the use of a nine-month recovery period from April through December rather than a five-month recovery period from August to December that was used for 2014. The shorter recovery period in 2014 was due to a delayed toll filing as a result of negotiations with shippers concerning certain components of the tariff rate structure.

On May 29, 2015, we filed FERC tariff No. 43.17.0 with an effective date of July 1, 2015 for our Lakehead system. We increased rates in compliance with the indexed rate ceilings allowed by the FERC, which incorporates the multiplier of 1.045829 issued by the FERC on May 14, 2015 in Docket No. RM93-11-000.

North Dakota System

Effective February 1, 2015, FERC tariff No. 3.6.0 established a new interconnection at Tioga, North Dakota.

Effective April 1, 2015, FERC tariff No. 3.7.0 updated the 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. The 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 \$0.44 per barrel, to an average of approximately \$1.77 per barrel. The Phase 5 Looping surcharge decreased primarily due to an increase in forecasted throughput, and the Phase 6 Mainline surcharge decreased due to an increase in forecasted throughput and in order to return prior period over-recoveries to shippers.

Effective April 22, 2015, FERC tariff No. 3.8.0 cancelled the transportation rate from Sherwood, North Dakota to Clearbrook, Minnesota as the pipeline no longer provides service from that receipt point.

Effective July 1, 2015, FERC tariff No. 3.10.0 increased rates in compliance with the indexed rate ceilings allowed by the FERC, which incorporates the multiplier of 1.045829 issued by the FERC on May 14, 2015 in Docket No. RM93-11-000.

Also effective July 1, 2015, FERC tariff No. 3.11.0 discounted the existing uncommitted rate from Berthold (pump-over), North Dakota to Berthold, North Dakota. The new tariff rate of \$0.27 per barrel reflects a rate decrease of \$0.556 per barrel. Additionally, as per 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 2014 and the forecasted operating costs and throughput for 2015.

Bakken System

Effective January 1, 2015, FERC tariff No. 3.2.0 was filed to reflect a change in the international joint rates. In accordance with FERC policy, each of the international joint rates was equal to or less than the sum of the local rates for the component movements from Berthold, North Dakota to Cromer, Manitoba.

Effective July 1, 2015, FERC tariff No. 2.2.0 increased rates in compliance with the indexed rate ceilings allowed by the FERC, which incorporates the multiplier of 1.045829 issued by the FERC on May 14, 2015 in Docket No. RM93-11-000.

Also effective July 1, 2015, FERC tariff No. 3.4.1 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 2014 and the forecasted operating costs and throughput for 2015.

Ozark System

Effective July 1, 2015, FERC tariff No. 48.5.0 increased rates in compliance with the indexed rate ceilings allowed by the FERC, which incorporates the multiplier of 1.045829 issued by the FERC on May 14, 2015 in Docket No. RM93-11-000.

SUBSEQUENT EVENTS

Distribution to Partners

On July 30, 2015, the board of directors of Enbridge Management declared a distribution payable to our partners on August 14, 2015. The distribution will be paid to unitholders of record as of August 7, 2015 of our available cash of \$257.9 million at June 30, 2015, or \$0.5830 per limited partner unit. Of this distribution, \$216.1 million will be paid in cash, \$41.0 million will be distributed in i-units to our i-unitholder, Enbridge Management, and due to the i-unit distribution, \$0.8 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.

Amendment of OLP Limited Partnership Agreement

Portions of the Eastern Access and Mainline Expansion capital programs have assets that have been placed into service, which generate distributable cash flow, and assets that are still under construction, which require capital funding. These assets are held, respectively, within the Series EA and Series ME of the OLP, which are jointly funded by our General Partner at 75% and by us at 25% under joint funding arrangements. As such, each quarter we and our General Partner receive a distribution for the assets in-service and provide required capital funding contribution requirements for assets under construction in proportion to their respective Series' ownership interests.

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 distributions commencing in the quarter ended June 30, 2015 through the quarter ending 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.

Distribution to Series EA Interests

On July 30, 2015, 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 the entire distribution of \$56.5 million to us.

Distribution to Series ME Interests

On July 30, 2015, 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 the entire distribution of \$14.8 million to us.

Series 1 Preferred Unit Amended Agreement

On July 30, 2015, we amended our limited partnership agreement to extend the payment deferral of for distributions accruing for the Series 1 Preferred Units through June 30, 2018, and to allow repayment of the accumulated deferral amount in equal amounts over a twelve-quarter period beginning the quarter ending March 31, 2019. In addition, the amendment extends the current preferred distribution accrual rate until June 30, 2020, and extends the date upon which the Series 1 Preferred Units become convertible into Class A common units to June 30, 2018.

Distribution from MEP

On July 29, 2015, the board of directors of Midcoast Holdings, L.L.C., acting in its capacity as the general partner of MEP, declared a cash distribution payable to MEP's partners on August 14, 2015. The distribution will be paid to unitholders of record as of August 7, 2015, of MEP's available cash of \$16.3 million at June 30, 2015, or

\$0.3525 per limited partner unit. MEP will pay \$7.5 million to their public Class A common unitholders, while \$8.8 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 29, 2015, the general partner of Midcoast Operating declared a cash distribution by Midcoast Operating payable to its partners of record as of August 7, 2015. Midcoast Operating will pay \$26.2 million to us and \$27.9 million to MEP.

On July 29, 2015, the partners of Midcoast Operating approved an amendment to Midcoast Operating's limited partnership agreement that would potentially enhance MEP's distributable cash flow, demonstrating our further support of MEP's ongoing cash distribution strategy and growth outlook. The amendment will provide a mechanism for MEP to receive increased quarterly distributions from Midcoast Operating and for us to receive reduced quarterly distributions if MEP's declared distribution exceeds its distributable cash, as that term is defined in Midcoast Operating's limited partnership agreement. 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 the Partnership's capital accounts in a liquidation scenario. The amendment to the limited partnership agreement and the support it provides to MEP's cash distribution is effective with the quarter ended June 30, 2015, and continues through and including the distribution made for the quarter ending December 31, 2017. For the second quarter of 2015, MEP did not receive an increased allocation of cash distributions from the Midcoast Operating as distributable cash flow generated in the second quarter exceeded the cash distribution amount declared for payout by 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 year ended December 31, 2014, in addition to information presented in Items 1 and 2 of this Quarterly Report on Form 10-Q. There have been no material changes to that information other than as presented below.

Our net income and cash flows are subject to volatility stemming from changes in interest rates on our variable rate debt obligations and fluctuations in commodity prices of natural gas, NGLs, condensate, crude oil and fractionation margins. Fractionation margins represent the relative difference between the price we receive from NGL and condensate sales and the corresponding 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, 2015.

Date of Maturity & Contract Type	Accounting Treatment	Notional	Average Fixed Rate ⁽¹⁾	Fair Value ⁽²⁾ at	
				June 30, 2015	December 31, 2014
(dollars in millions)					
Contracts maturing in 2015					
Interest Rate Swaps – Pay Fixed	Cash Flow Hedge	\$ 510	1.53%	\$ —	\$ (0.2)
Contracts maturing in 2016					
Interest Rate Swaps – Pay Fixed	Cash Flow Hedge	\$ 90	0.55%	\$ (0.1)	\$ (0.1)
Contracts maturing in 2017					
Interest Rate Swaps – Pay Fixed	Cash Flow Hedge	\$ 500	2.21%	\$ (11.5)	\$ (12.9)
Contracts maturing in 2018					
Interest Rate Swaps – Pay Fixed	Cash Flow Hedge	\$ 810	2.24%	\$ (5.1)	\$ (1.3)
Contracts maturing in 2019					
Interest Rate Swaps – Pay Fixed	Cash Flow Hedge	\$ 620	2.96%	\$ (4.0)	\$ (3.3)
Contracts settling prior to maturity					
2015 – Pre-issuance Hedges	Cash Flow Hedge	\$1,000	5.48%	\$(254.6)	\$(258.3)
2016 – Pre-issuance Hedges	Cash Flow Hedge	\$ 500	4.21%	\$ (57.1)	\$ (63.4)
2017 – Pre-issuance Hedges	Cash Flow Hedge	\$ 500	3.69%	\$ (25.6)	\$ (36.0)
2018 – Pre-issuance Hedges	Cash Flow Hedge	\$ 350	3.08%	\$ 3.7	\$ (4.9)

⁽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, 2015 and December 31, 2014, 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 \$1.7 million and \$37.4 million at June 30, 2015 and December 31, 2014, 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, 2015 and December 31, 2014.

Commodity	Notional ⁽¹⁾	At June 30, 2015				At December 31, 2014		
		Wtd. Average Price ⁽²⁾		Fair Value ⁽³⁾		Fair Value ⁽³⁾		(in millions)
		Receive	Pay	Asset	Liability	Asset	Liability	
Portion of contracts maturing in 2015								
<i>Swaps</i>								
Receive variable/pay fixed	Natural Gas	1,558,292	\$ 2.77	\$ 2.83	\$ 0.1	\$ (0.2)	\$ —	\$ (0.7)
	NGL	901,000	\$32.48	\$36.64	\$ 0.1	\$ (3.8)	\$ —	\$ (6.8)
	Crude Oil	504,000	\$60.30	\$84.19	\$ —	\$ (12.0)	\$ —	\$ (27.4)
Receive fixed/pay variable	Natural Gas	2,550,938	\$ 3.00	\$ 2.83	\$ 0.5	\$ —	\$ 3.7	\$ —
	NGL	1,720,600	\$38.80	\$28.84	\$17.4	\$ (0.3)	\$39.2	\$ —
	Crude Oil	961,064	\$91.18	\$60.31	\$29.5	\$ —	\$65.0	\$ —
Receive variable/pay variable . .	Natural Gas	47,491,500	\$ 2.73	\$ 2.72	\$ 1.5	\$ (1.2)	\$ 1.5	\$ (1.7)
<i>Physical Contracts</i>								
Receive variable/pay fixed	Natural Gas	106,700	\$ 2.66	\$ 2.70	\$ —	\$ —	\$ —	\$ —
	NGL	767,000	\$11.59	\$11.40	\$ 0.2	\$ (0.1)	\$ —	\$ (3.6)
	Crude Oil	33,400	\$59.60	\$59.45	\$ —	\$ —	\$ —	\$ —
Receive fixed/pay variable	Natural Gas	209,936	\$ 2.81	\$ 2.73	\$ —	\$ —	\$ —	\$ —
	NGL	3,396,447	\$21.07	\$19.97	\$ 4.9	\$ (1.2)	\$19.8	\$ —
	Crude Oil	107,000	\$59.58	\$59.69	\$ —	\$ (0.1)	\$ 0.5	\$ —
Receive variable/pay variable . .	Natural Gas	136,481,498	\$ 2.80	\$ 2.79	\$ 1.1	\$ (0.2)	\$ 2.2	\$ (1.0)
	NGL	8,585,747	\$23.33	\$22.75	\$ 5.6	\$ (0.6)	\$ 3.7	\$ (1.0)
	Crude Oil	911,227	\$58.61	\$58.91	\$ 1.1	\$ (1.4)	\$ 0.3	\$ (1.7)
Portion of contracts maturing in 2016								
<i>Swaps</i>								
Receive variable/pay fixed	Natural Gas	363,514	\$ 2.83	\$ 3.41	\$ —	\$ (0.2)	\$ —	\$ (0.1)
	NGL	823,500	\$28.45	\$30.70	\$ —	\$ (1.8)	\$ —	\$ —
	Crude Oil	415,950	\$62.01	\$82.69	\$ —	\$ (8.6)	\$ —	\$ (8.1)
Receive fixed/pay variable	Natural Gas	1,898,100	\$ 3.21	\$ 3.24	\$ 0.1	\$ (0.1)	\$ —	\$ —
	NGL	883,500	\$38.48	\$28.05	\$ 9.2	\$ —	\$ 9.3	\$ —
	Crude Oil	769,270	\$74.36	\$62.04	\$ 9.5	\$ (0.1)	\$ 9.1	\$ —
Receive variable/pay variable . .	Natural Gas	50,739,000	\$ 3.01	\$ 2.99	\$ 1.6	\$ (1.0)	\$ 0.5	\$ (0.3)
<i>Physical Contracts</i>								
Receive variable/pay fixed	NGL	—	\$ —	\$ —	\$ —	\$ —	\$ —	\$ —
Receive fixed/pay variable	Natural Gas	63,850	\$ 3.11	\$ 3.06	\$ —	\$ —	\$ —	\$ —
	NGL	38,963	\$32.99	\$31.84	\$ 0.1	\$ —	\$ —	\$ —
Receive variable/pay variable . .	Natural Gas	99,005,643	\$ 3.13	\$ 3.12	\$ 0.8	\$ —	\$ 0.7	\$ (0.4)
	NGL	9,676,152	\$21.94	\$21.76	\$ 1.8	\$ —	\$ —	\$ —
	Crude Oil	30,400	\$61.65	\$59.30	\$ 0.1	\$ —	\$ —	\$ —
Portion of contracts maturing in 2017								
<i>Swaps</i>								
Receive variable/pay fixed	Natural Gas	24,030	\$ 3.27	\$ 3.48	\$ —	\$ —	\$ —	\$ —
	NGL	547,500	\$23.14	\$25.86	\$ —	\$ (1.5)	\$ —	\$ —
	Crude Oil	547,500	\$63.62	\$66.72	\$ —	\$ (1.7)	\$ —	\$ —
Receive fixed/pay variable	NGL	547,500	\$23.59	\$23.14	\$ 0.6	\$ (0.3)	\$ 0.7	\$ —
	Crude Oil	547,500	\$66.78	\$63.62	\$ 2.1	\$ (0.4)	\$ 0.8	\$ —
Receive variable/pay variable . .	Natural Gas	5,910,000	\$ 3.24	\$ 3.20	\$ 0.2	\$ —	\$ —	\$ —
<i>Physical Contracts</i>								
Receive variable/pay variable . .	Natural Gas	28,097,550	\$ 3.39	\$ 3.38	\$ 0.2	\$ —	\$ 0.2	\$ (0.1)
Portion of contracts maturing in 2018								
<i>Physical Contracts</i>								
Receive variable/pay variable . .	Natural Gas	5,787,810	\$ 3.57	\$ 3.56	\$ 0.1	\$ —	\$ —	\$ —
Portion of contracts maturing in 2019								
<i>Physical Contracts</i>								
Receive variable/pay variable . .	Natural Gas	2,187,810	\$ 3.54	\$ 3.51	\$ —	\$ —	\$ —	\$ —
Portion of contracts maturing in 2020								
<i>Physical Contracts</i>								
Receive variable/pay variable . .	Natural Gas	359,640	\$ 3.86	\$ 3.83	\$ —	\$ —	\$ —	\$ —

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

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

⁽³⁾ The fair value is determined based on quoted market prices at June 30, 2015 and December 31, 2014, 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 \$0.0 million and \$0.5 million at June 30, 2015 and December 31, 2014, 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, 2015 and December 31, 2014.

Commodity	At June 30, 2015				At December 31, 2014			
	Notional ⁽¹⁾	Strike Price ⁽²⁾	Market Price ⁽²⁾	Fair Value ⁽³⁾		Fair Value ⁽³⁾		
				Asset	Liability	Asset	Liability	
(in millions)								
Portion of option contracts maturing in 2015								
Puts (purchased)	Natural Gas	2,024,000	\$ 3.90	\$ 2.90	\$ 2.1	\$ —	\$ 3.8	\$ —
	NGL	1,159,200	\$43.32	\$25.70	\$20.6	\$ —	\$40.2	\$ —
	Crude Oil	368,000	\$81.56	\$60.38	\$ 7.9	\$ —	\$18.8	\$ —
Calls (written)	Natural Gas	644,000	\$ 5.05	\$ 2.90	\$ —	\$ —	\$ —	\$ —
	NGL	745,200	\$45.80	\$24.93	\$ —	\$(0.1)	\$ —	\$(0.6)
	Crude Oil	368,000	\$88.39	\$60.38	\$ —	\$ —	\$ —	\$(0.4)
Puts (written)	Natural Gas	2,024,000	\$ 3.90	\$ 2.91	\$ —	\$(2.1)	\$ —	\$(3.8)
	NGL	46,000	\$77.28	\$51.86	\$ —	\$(1.2)	\$ —	\$ —
Calls (purchased)	Natural Gas	644,000	\$ 5.05	\$ 2.90	\$ —	\$ —	\$ —	\$ —
Portion of option contracts maturing in 2016								
Puts (purchased)	Natural Gas	1,647,000	\$ 3.75	\$ 3.17	\$ 1.2	\$ —	\$ 1.0	\$ —
	NGL	2,836,500	\$39.24	\$27.06	\$38.9	\$ —	\$39.3	\$ —
	Crude Oil	805,200	\$75.91	\$62.08	\$12.9	\$ —	\$14.7	\$ —
Calls (written)	Natural Gas	1,647,000	\$ 4.98	\$ 3.17	\$ —	\$(0.1)	\$ —	\$(0.1)
	NGL	2,836,500	\$45.14	\$27.06	\$ —	\$(2.8)	\$ —	\$(3.2)
	Crude Oil	805,200	\$86.68	\$62.08	\$ —	\$(0.8)	\$ —	\$(2.7)
Puts (written)	Natural Gas	1,647,000	\$ 3.75	\$ 3.17	\$ —	\$(1.2)	\$ —	\$(1.0)
	NGL	91,500	\$39.06	\$29.66	\$ —	\$(1.1)	\$ —	\$ —
Calls (purchased)	Natural Gas	1,647,000	\$ 4.98	\$ 3.17	\$ 0.1	\$ —	\$ 0.1	\$ —
	NGL	91,500	\$46.41	\$29.66	\$ 0.1	\$ —	\$ —	\$ —
Portion of option contracts maturing in 2017								
Puts (purchased)	NGL	547,500	\$21.70	\$23.14	\$ 0.8	\$ —	\$ 1.2	\$ —
	Crude Oil	547,500	\$63.00	\$63.62	\$ 4.3	\$ —	\$ 4.1	\$ —
Calls (written)	NGL	547,500	\$25.34	\$23.14	\$ —	\$(0.6)	\$ —	\$(0.7)
	Crude Oil	547,500	\$71.45	\$63.62	\$ —	\$(2.7)	\$ —	\$(3.3)

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

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

⁽³⁾ The fair value is determined based on quoted market prices at June 30, 2015 and December 31, 2014, 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 \$0.2 million and \$0.7 million at June 30, 2015 and December 31, 2014, respectively, as well as cash collateral received.

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

Counterparty Credit Quality ⁽¹⁾	June 30, 2015	December 31, 2014
	(in millions)	
AAA	\$ 0.1	\$ 0.1
AA ⁽²⁾	(68.5)	(49.8)
A	(84.5)	(129.1)
Lower than A	(83.6)	17.9
	<u>\$(236.5)</u>	<u>\$(160.9)</u>

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

⁽²⁾ Includes \$11.5 million and \$28.4 million held of cash collateral at June 30, 2015 and December 31, 2014, respectively.

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, 2015. Based upon that evaluation, our principal executive and principal financial officers concluded that our disclosure controls and procedures are effective at the reasonable assurance level. In conducting this assessment, our management relied on similar evaluations conducted by employees of Enbridge affiliates who provide certain treasury, accounting and other services on our behalf.

There have been no changes in internal control over financial reporting that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting during the three months ended June 30, 2015.

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

There have been no material changes to our risk factors previously disclosed in our Annual Report on Form 10-K for the fiscal year ended December 31, 2014, filed with the SEC on February 18, 2015.

Item 5. Other Information

On July 30, 2015, the Partnership and the other partners entered into the Seventh Amended and Restated Agreement of Limited Partnership of Enbridge Energy, Limited Partnership (the “EELP Partnership Agreement”). The EELP Partnership Agreement provides that our General Partner will forego Series EA and ME distributions commencing in the quarter ended June 30, 2015 through and including the quarter ending 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, the Partnership 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.

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 30, 2015

By: /s/ Mark A. Maki

Mark A. Maki
*President and
Principal Executive Officer*

Date: July 30, 2015

By: /s/ Stephen J. Neyland

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

Index of Exhibits

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

Exhibit Number	Description
3.1	Amendment No. 1 to Seventh Amended and Restated Agreement of Limited Partnership of Enbridge Energy Partners, L.P. (incorporated by reference to Exhibit 3.1 of our Current Report on Form 8-K, filed on July 30, 2015).
10.1	Amendment No. 6 to Credit Agreement and Extension and Decrease Agreement, dated as of July 2, 2015, by and among Enbridge Energy Partners, L.P., the lenders parties thereto and JPMorgan Chase Bank, National Association (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K, filed on July 8, 2015).
10.2*	Seventh Amended and Restated Agreement of Limited Partnership of Enbridge Energy, Limited Partners, dated July 30, 2015, by and among and Enbridge Energy Partners, L.P., Enbridge Pipelines (Lakehead) L.L.C., Enbridge Pipelines (Wisconsin) Inc., Enbridge Energy Company, Inc., Enbridge Pipelines (Eastern Access) L.L.C. and Enbridge Pipelines (Mainline Expansion) L.L.C.
31.1*	Certification of Principal Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2*	Certification of Principal Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1*	Certification of Principal Executive Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2*	Certification of Principal Financial Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
101.INS*	XBRL Instance Document.
101.SCH*	XBRL Taxonomy Extension Schema Document.
101.CAL*	XBRL Taxonomy Extension Calculation Linkbase Document.
101.DEF*	XBRL Taxonomy Extension Definition Linkbase Document.
101.LAB*	XBRL Taxonomy Extension Label Linkbase Document.
101.PRE*	XBRL Taxonomy Extension Presentation Linkbase Document.

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 30, 2015

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)*

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 30, 2015

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)

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, 2015 (the "Quarterly Report") filed with the United States Securities and Exchange Commission pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m(a) or 78o(d)), as amended, fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended, and that the information contained in the Quarterly Report fairly presents, in all material respects, the financial condition and results of operations of the Partnership.

Date: July 30, 2015

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)

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, 2015 (the "Quarterly Report") filed with the United States Securities and Exchange Commission pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m(a) or 78o(d)), as amended, fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended, and that the information contained in the Quarterly Report fairly presents, in all material respects, the financial condition and results of operations of the Partnership.

Date: July 30, 2015

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)