ENBRIDGE ENERGY PARTNERS LP

FORM 10-Q
(Quarterly Report)

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

FORM 10-Q

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

For the quarterly period ended March 31, 2015

OR

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

For the transition period from to

Commission file number 1-10934

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

Delaware	**39-1715850**
(State or Other Jurisdiction of Incorporation or Organization)	**(I.R.S. Employer Identification No.)**

1100 Louisiana Street,
Suite 3300
Houston, Texas 77002
(Address of Principal Executive Offices) (Zip Code)

(713) 821-2000
(Registrant's Telephone Number, Including Area Code)

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ☒ No ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one):

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

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

The registrant had 262,208,428 Class A common units outstanding as of May 1, 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 U.S. Securities and Exchange Commission's, or SEC's, website (www.sec.gov) and at our website (www.enbridgepartners.com).

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PART I—FINANCIAL INFORMATION

Item 1. Financial Statements

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

	For the three-month period ended March 31, 2015	2014
	(unaudited; in millions, except per unit amounts)	
Operating revenues:		
Commodity sales (Note 11)	$ 800.9	$ 1,542.3
Commodity sales—affiliate (Note 9)	21.8	57.2
Transportation and other services (Note 11)	574.7	462.2
Transportation and other services—affiliate (Note 9)	31.2	17.9
	1,428.6	2,079.6
Operating expenses:		
Commodity costs (Notes 5 and 11)	761.2	1,458.5
Commodity costs—affiliate (Note 9)	17.9	30.2
Environmental costs, net of recoveries (Note 10)	0.8	5.0
Operating and administrative (Notes 6 and 10)	98.2	96.6
Operating and administrative—affiliate (Note 9)	118.9	120.4
Power (Note 11)	63.6	50.4
Depreciation and amortization (Note 6)	128.4	103.8
	1,189.0	1,864.9
Operating income	239.6	214.7
Interest expense, net (Notes 7 and 11)	48.3	76.9
Allowance for equity used during construction (Note 15)	23.0	20.7
Other income (expense) (Notes 10 and 15)	5.9	(0.8)
Income before income tax expense	220.2	157.7
Income tax expense (Note 12)	2.4	2.0
Net income	217.8	155.7
Less: Net income attributable to:		
Noncontrolling interest (Note 9)	51.3	36.3
Series 1 preferred unit distributions	22.5	22.5
Accretion of discount on Series 1 preferred units	3.9	3.6
Net income attributable to general and limited partner ownership interests in Enbridge Energy Partners, L.P.	$ 140.1	$ 93.3
Net income allocable to common units and i-units	$ 85.9	$ 58.9
Net income per common unit and i-unit (basic) (Note 2)	$ 0.26	$ 0.18
Weighted average common units and i-units outstanding (basic)	332.6	326.4
Net income per common unit and i-unit (diluted) (Note 2)	$ 0.26	$ 0.18
Weighted average common units and i-units outstanding (diluted)	332.6	326.4

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-month period ended March 31,	
	2015	2014
	(unaudited; in millions)	
Net income	$ 217.8	$ 155.7
Other comprehensive loss, net of tax expense of $0.0 million (Note 11)	(146.8)	(70.0)
Comprehensive income	71.0	85.7
Less: Comprehensive income attributable to:		
Noncontrolling interest (Note 9)	51.3	36.3
Series 1 preferred unit distributions	22.5	22.5
Accretion of discount on Series 1 preferred units	3.9	3.6
Other comprehensive loss allocated to noncontrolling interest	(0.7)	—
Comprehensive income (loss) attributable to general and limited partner ownership interests in Enbridge Energy Partners, L.P.	$ (6.0)	$ 23.3

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

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

	For the three-month period ended March 31, 2015	2014
	(unaudited; in millions)	
Cash provided by operating activities:		
Net income	$ 217.8	$ 155.7
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization (Note 6)	128.4	103.8
Derivative fair value net losses (Note 11)	10.3	3.3
Inventory market price adjustments (Note 5)	4.6	1.5
Environmental costs, net of recoveries (Note 10)	(0.2)	4.4
Distributions from investments in joint ventures (Note 9)	5.7	1.6
Equity loss (earnings) from investments in joint ventures (Note 9)	(5.7)	1.3
Allowance for equity used during construction (Note 15)	(23.0)	(20.7)
Other	4.4	2.7
Changes in operating assets and liabilities, net of acquisitions:		
Receivables, trade and other	10.6	(14.5)
Due from General Partner and affiliates	(55.6)	4.5
Accrued receivables	190.4	74.6
Inventory (Note 5)	56.2	26.9
Current and long-term other assets (Note 11)	(13.9)	(4.8)
Due to General Partner and affiliates	12.9	(11.0)
Accounts payable and other (Notes 4 and 11)	(36.2)	(85.0)
Environmental liabilities (Note 10)	(7.7)	(42.0)
Accrued purchases	(121.3)	(6.3)
Interest payable	(0.8)	5.7
Property and other taxes payable	3.6	9.1
Net cash provided by operating activities	380.5	210.8
Cash used in investing activities:		
Additions to property, plant and equipment (Notes 6 and 14)	(460.0)	(612.8)
Asset acquisitions (Note 3)	(85.1)	—
Changes in restricted cash (Note 9)	40.4	52.6
Investments in joint ventures (Note 9)	(1.9)	(7.3)
Distributions from investments in joint ventures in excess of cumulative earnings	2.4	—
Other	0.2	(0.3)
Net cash used in investing activities	(504.0)	(567.8)
Cash provided by financing activities:		
Net proceeds from unit issuances (Note 8)	294.8	—
Distributions to partners (Note 8)	(194.2)	(178.4)
Repayments to General Partner (Note 9)	(306.0)	(6.0)
Net borrowings (repayments) under credit facility (Note 7)	155.0	(85.0)
Net commercial paper borrowings (Note 7)	165.0	390.1
Contributions from noncontrolling interest (Notes 8 and 9)	199.5	289.7
Distributions to noncontrolling interest (Notes 8 and 9)	(107.0)	(16.3)
Net cash provided by financing activities	207.1	394.1
Net increase in cash and cash equivalents	83.6	37.1
Cash and cash equivalents at beginning of year	197.9	164.8
Cash and cash equivalents at end of period	$ 281.5	$ 201.9

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

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

	March 31, 2015	December 31, 2014
	(unaudited; in millions)	
ASSETS		
Current assets:		
Cash and cash equivalents (Note 4)	$ 281.5	$ 197.9
Restricted cash (Notes 9 and 11)	74.6	97.0
Receivables, trade and other, net of allowance for doubtful accounts of $1.8 million at March 31, 2015 and December 31, 2014 (Note 10)	35.6	46.2
Due from General Partner and affiliates	97.1	41.4
Accrued receivables	69.9	260.3
Inventory (Note 5)	33.4	94.2
Other current assets (Note 11)	194.6	218.4
	786.7	955.4
Property, plant and equipment, net (Notes 6 and 15)	16,157.9	15,692.7
Goodwill	246.7	246.7
Intangible assets, net	285.1	254.8
Other assets, net (Note 11)	580.3	597.3
	$18,056.7	$ 17,746.9
LIABILITIES AND PARTNERS' CAPITAL		
Current liabilities:		
Due to General Partner and affiliates (Note 9)	$ 156.6	$ 143.7
Accounts payable and other (Notes 4, 11 and 15)	857.8	777.7
Environmental liabilities (Note 10)	125.4	141.7
Accrued purchases	254.4	375.7
Interest payable	73.8	74.6
Property and other taxes payable (Note 12)	100.1	96.5
Note payable to General Partner (Note 9)	—	306.0
	1,568.1	1,915.9
Long-term debt (Note 7)	6,995.5	6,675.2
Due to General Partner and affiliates (Note 9)	170.8	148.3
Other long-term liabilities (Notes 10, 11 and 12)	351.3	278.1
	9,085.7	9,017.5
Commitments and contingencies (Note 10)		
Partners' capital: (Notes 8 and 9)		
Series 1 preferred units (48,000,000 authorized and issued at March 31, 2015 and December 31, 2014)	1,179.5	1,175.6
Class D units (66,100,000 authorized and issued at March 31, 2015 and December 31, 2014)	2,516.8	2,516.8
Class E units (18,114,975 authorized and issued at March 31, 2015)	778.0	—
Class A common units (262,208,428 and 254,208,428 authorized and issued at March 31, 2015 and December 31, 2014, respectively)	208.8	235.5
Class B common units (7,825,500 authorized and issued at March 31, 2015 and December 31, 2014)	0.1	—
i-units (69,343,562 and 68,305,187 authorized and issued at March 31, 2015 and December 31, 2014, respectively)	609.6	712.6
Incentive distribution units (1,000 authorized and issued at March 31, 2015 and December 31, 2014)	493.2	493.0
General Partner	194.1	198.3
Accumulated other comprehensive loss (Note 11)	(357.5)	(211.4)
Total Enbridge Energy Partners, L.P. partners' capital	5,622.6	5,120.4
Noncontrolling interest (Note 9)	3,348.4	3,609.0
Total partners' capital	8,971.0	8,729.4
	$18,056.7	$ 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 accounting principles generally accepted in the United States, or GAAP, for interim consolidated financial information and with the instructions to Form 10-Q and Rule 10-01 of Regulation S-X. Accordingly, the unaudited interim consolidated financial statements do not include all the information and footnotes required by GAAP for complete consolidated financial statements. In the opinion of management, they contain all adjustments, consisting only of normal recurring adjustments, which management considers necessary to present fairly our financial position as of March 31, 2015, our results of operations for the three-month periods ended March 31, 2015 and 2014, and our cash flows for the three-month periods ended March 31, 2015 and 2014. We derived our consolidated statement of financial position as of December 31, 2014, from the audited financial statements included in our Annual Report on Form 10-K for the fiscal year ended December 31, 2014. Our results of operations for the three-month periods ended March 31, 2015 and 2014, should not be taken as indicative of the results to be expected for the full year due to seasonal fluctuations in the supply of and demand for 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 also allocate any earnings in excess of distributions to our General Partner and limited partners 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 based on their sharing of losses of 2% and 98%, respectively, as set forth in our partnership agreement. We calculate distributions to the General Partner and limited partners based upon the distribution rates and percentages set forth in the following table:

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

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

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 (i) 66.1 million units of a new class of limited partner interests designated as Class D units, and (ii) 1,000 units of a new class of limited partner interests designated as Incentive Distribution Units, or

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IDUs. Prior to this transaction, and for the three-month period ended March 31, 2014, we allocated distributions to the General Partner and limited partners as follows:

Distribution Targets	Portion of Quarterly Distribution Per Unit	Percentage Distributed to General Partner	Percentage Distributed to Limited partners
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 %

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 8. *Partners' Capital* of our consolidated financial statements.

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

	For the three-month period ended March 31,	
	2015	2014
	(in millions, except per unit amounts)	
Net income	$ 217.8	$ 155.7
Less Net income attributable to:		
Noncontrolling interest	(51.3)	(36.3)
Series 1 preferred unit distributions	(22.5)	(22.5)
Accretion of discount on Series 1 preferred units	(3.9)	(3.6)
Net income attributable to general and limited partner interests in Enbridge Energy Partners, L.P.	140.1	93.3
Less distributions:		
Incentive distributions	(3.4)	(33.2)
Distributed earnings attributed to our General Partner	(5.0)	(3.6)
Distributed earnings attributed to Class D and Class E units	(48.0)	—
Total distributed earnings to our General Partner, Class D and Class E units and IDUs	(56.4)	(36.8)
Total distributed earnings attributed to our common units and i-units	(193.5)	(177.7)
Total distributed earnings	(249.9)	(214.5)
Overdistributed earnings	$ (109.8)	$ (121.2)
Weighted average common units and i-units outstanding	332.6	326.4
Basic and diluted earnings per unit:		
Distributed earnings per common unit and i-unit [(1)]	$ 0.58	$ 0.54
Overdistributed earnings per common unit and i-unit [(2)]	(0.32)	(0.36)
Net income per common unit and i-unit (basic and diluted) [(3)]	$ 0.26	$ 0.18

(1) Represents the total distributed earnings to common units and i-units divided by the weighted average number of common units and i-units outstanding for the period.
(2) Represents the common units' and i-units' share (98%) of distributions in excess of earnings divided by the weighted average number of common units and i-units outstanding for the period and overdistributed earnings allocated to the common units and i-units based on the distribution waterfall that is outlined in our partnership agreement.
(3) For the three-month period ended March 31, 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-month period ended March 31, 2014, 43,201,310 anti-dilutive Preferred units were excluded from the if-converted method of calculating diluted earnings per unit.

3. ACQUISITIONS

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

On February 27, 2015, 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. Of the $85.1 million purchase price, $20.0 million was placed into escrow, pending the resolution of a legal matter and NGR's completion of additional wells connecting to our system. During March 2015, $2.0 million was released from escrow and paid to NGR. The remaining $18.0 million in escrow has been classified as "Restricted cash" in our condensed consolidated statement of financial position as of March 31, 2015.

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

The acquisition consisted of a natural gas gathering system that is currently in operation moving equity and third party production. Funding was provided by us and MEP based on our proportionate ownership percentages in Midcoast Operating, which are 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 $20.5 million at March 31, 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 March 31, 2015.

5. INVENTORY

Our inventory is comprised of the following:

	March 31, 2015		December 31, 2014
		(in millions)	
Materials and supplies	$ 2.2		$ 2.2
Crude oil inventory	8.7		13.2
Natural gas and NGL inventory	22.5		78.8
	$ 33.4		$ 94.2

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

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6. PROPERTY, PLANT AND EQUIPMENT

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

	March 31, 2015	December 31, 2014
	(in millions)	
Land	$ 45.4	$ 44.2
Rights-of-way	861.6	851.8
Pipelines	9,674.6	9,585.4
Pumping equipment, buildings and tanks	3,275.7	3,126.8
Compressors, meters and other operating equipment	2,096.6	2,072.7
Vehicles, office furniture and equipment	426.0	413.9
Processing and treating plants	527.3	516.0
Construction in progress	2,148.5	1,857.1
Total property, plant and equipment	19,055.7	18,467.9
Accumulated depreciation	(2,897.8)	(2,775.2)
Property, plant and equipment, net	$16,157.9	$ 15,692.7

7. DEBT

The following table presents the primary components of our outstanding indebtedness with third parties and the weighted average interest rates associated with each component as of March 31, 2015, before the effect of our interest rate hedging activities. Our indebtedness with related parties is discussed in Note 9. *Related Party Transactions.*

	Interest Rate	March 31, 2015	December 31, 2014
		(in millions)	
EEP debt obligations:			
Commercial Paper [(1)]	0.713%	$ 777.4	$ 612.3
Credit Facilities due 2016-2019	1.22%-1.28%	1,360.0	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	2.675%	315.0	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		7,002.4	6,682.3
Other:			
Unamortized Discount		(6.9)	(7.1)
Total Long Term Debt		$6,995.5	$ 6,675.2

(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-month periods ended March 31, 2015, and 2014, is comprised of the following:

	For the three-month period ended March 31,	
	2015	2014
	(in millions)	
Interest expense	$ 48.3	$ 76.9
Interest capitalized	12.2	13.9
Interest cost incurred	$ 60.5	$ 90.8

The $28.6 million decrease in interest expense for the three-month period ended March 31, 2015, as compared with the same period in 2014 was due to changes to interest expense from ineffectiveness on hedging instruments.

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.

The 364-Day Credit Facility matures on July 3, 2015 and provides aggregate lending commitments of up to $650.0 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. Together, the Credit Facilities provide an aggregate amount of approximately $2.625 billion of bank credit, as of March 31, 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 March 31, 2015, we had approximately $777.4 million in principal amount of commercial paper outstanding at a weighted average interest rate of 0.71%, excluding the effect of our interest rate hedging activities. Under our commercial paper program, we had net borrowings of approximately $165.0 million during the three-month period ended March 31, 2015, which includes gross borrowings of $2,807.2 million and gross repayments of $2,642.2 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.

Taking that policy into account, at March 31, 2015, we have approximately $877.4 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	$ 2,625.0
Total credit available under the EUS 364-day Credit Facility	750.0
Less: Amounts outstanding under our Credit Facilities	1,360.0
Principal amount of commercial paper outstanding	777.4
EUS 364-day Credit Facility [1]	—
Letters of credit outstanding	360.2
Total amount available at March 31, 2015	$ 877.4

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

As of March 31, 2015, we were in compliance with the terms of all of our financial covenants under the 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 March 31, 2015, MEP had $315.0 million in outstanding borrowings under the MEP Credit Agreement at a weighted average interest rate of 2.7%. Under the MEP Credit Agreement, MEP had net repayments of approximately $45.0 million during the three-month period ended March 31, 2015, which includes gross borrowings of $1,150.0 million and gross repayments of $1,195.0 million. As of March 31, 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, commencing on March 31, 2015. At March 31, 2015, MEP was in compliance with the terms of its financial covenants under the 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 March 31, 2015, and December 31, 2014, respectively, due to the short-term nature and frequent repricing of the amounts outstanding under these obligations. The 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.

The approximate fair values of our fixed-rate debt obligations was $5.2 billion and $5.1 billion at March 31, 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.

8. PARTNERS' CAPITAL

Distribution to Partners

The following table sets forth our distributions, as approved by the board of directors of Enbridge Energy Management, or Enbridge Management, during the three-month period ended March 31, 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)			
January 29, 2015	February 6, 2015	February 13, 2015	$ 0.5700	$ 233.9	$ 38.9	$ 0.8	$ 194.2

(1) We issued 1,038,375 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.

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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, and MEP, for the three-month periods ended March 31, 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 MEP arises from its public unitholders' ownership interests in MEP.

	For the three-month period ended March 31,	
	2015	2014
	(in millions)	
Series 1 Preferred interests		
Beginning balance	$1,175.6	$1,160.7
Net income	22.5	22.5
Accretion of discount on preferred units	3.9	3.6
Distribution payable	(22.5)	(22.5)
Ending balance	$1,179.5	$1,164.3 (1)
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	140.1	93.3
Distributions	(194.2)	(178.4)
Acquisition of noncontrolling interest in subsidiary	403.7	—
Ending balance	$4,800.6	$4,552.6 (1)
Accumulated other comprehensive loss		
Beginning balance	$ (211.4)	$ (76.6)
Changes in fair value of derivative financial instruments reclassified to earnings	(1.0)	11.2
Changes in fair value of derivative financial instruments recognized in other comprehensive income (loss)	(145.1)	(81.2)
Ending balance	$ (357.5)	$ (146.6)
Noncontrolling interest		
Beginning balance	$3,609.0	$1,975.6
Capital contributions	199.5	289.7
Acquisition of noncontrolling interest in subsidiary	(403.7)	—
Other comprehensive loss allocated to noncontrolling interest	(0.7)	—
Net income	51.3	36.3
Distributions to noncontrolling interest	(107.0)	(16.3)
Ending balance	$3,348.4	$2,285.3
Total partners' capital at end of period	$8,971.0	$7,855.6

(1) After filing our Quarterly Report on Form 10-Q , for the quarterly period ended March 31, 2014, we determined that the beneficial conversion feature of our preferred units in the amount of $47.7 million was incorrectly presented in the significant changes in our partners' capital table. The presentation error resulted in an understatement of the Series 1 Preferred interests and an overstatement of the General and limited partner interests by $47.7 million at March 31, 2014. We concluded that this error is immaterial to the prior interim financial statements for the three-month period ended March 31, 2014. This error did not affect our total partners' capital at March 31, 2014, or our cash flows or earnings for the three-month period ended March 31, 2014. We have presented the corrected items for the three-month period ended March 31, 2014.

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.

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.

Shelf-Registration Statement

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 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.

2015 Issuance Date	Number of Class A common units Issued	Offering Price per Class A common unit	Net Proceeds to the Partnership [1]	General Partner Contribution [2]	Net Proceeds Including General Partner Contribution
		(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.

9. RELATED PARTY TRANSACTIONS

Administrative and Workforce Related Services

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

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

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, (i) on a revolving basis for a 364-day period and (ii) for a 364-day term on a non-revolving basis following the expiration of the revolving period. Loans under the EUS 364-day Credit Facility accrue interest 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 March 31, 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 (i) debt or equity securities in a registered public offering, or (ii) limited partnership interests in Midcoast Operating to MEP.

Distribution from MEP

The following table presents distributions paid by MEP to its Class A common unitholders and us during the three-month period ended March 31, 2015, representing the noncontrolling interest in MEP.

Distribution Declaration Date	Distribution Payment Date	Amount Paid to EEP	Amount Paid to the noncontrolling interest	Total MEP Distribution
			(in millions)	
January 28, 2015	February 13, 2015	$ 8.5	$ 7.3	$ 15.8

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 during the three-month period ended March 31, 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.

Distribution Declaration Date	Distribution Payment Date	Amount Paid to Partnership	Amount paid to the noncontrolling interest	Total Series AC Distribution
			(in millions)	
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 projects are jointly funded by our General Partner at 75% and us at 25%.

Our General Partner made equity contributions totaling $36.8 million and $178.5 million to the OLP during the three-month periods ended March 31, 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 three-month period ended March 31, 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.

Distribution Declaration Date	Distribution Payment Date	Amount Paid to EEP	Amount Paid to the noncontrolling interest	Total Series EA Distribution
			(in millions)	
January 29, 2015	February 13, 2015	$ 22.3	$ 67.0	$ 89.3

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 $162.7 million and $74.3 million to the OLP for the three-month periods ended March 31, 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 three-month period ended March 31, 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.

Distribution Declaration Date	Distribution Payment Date	Amount Paid to EEP	Amount Paid to the noncontrolling interest	Total Series ME Distribution
			(in millions)	
January 29, 2015	February 13, 2015	$ 1.8	$ 5.2	$ 7.0

Noncontrolling Interests

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

	For the three-month period ended March 31	
	2015	2014
	(in millions)	
Alberta Clipper Interests	$ (0.8)	$ 10.1
Eastern Access Interests	44.8	21.6
U.S. Mainline Expansion Interests	16.5	4.4
Midcoast Energy Partners, L.P.	(9.2)	0.2
Total	$ 51.3	$ 36.3

Sale of Accounts Receivable

For the three-month periods ended March 31, 2015 and 2014, we sold and derecognized $1,095.9 million and $1,296.7 million, respectively, of receivables to a wholly-owned subsidiary of Enbridge. For the three-month periods ended March 31, 2015 and 2014, we received cash proceeds of $1,095.6 million and $1,296.4 million, respectively. As of March 31, 2015, $363.7 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-month periods ended March 31, 2015 and 2014, the cost stemming from the discount on the receivables sold was not material.

As of March 31, 2015 and December 31, 2014, we had $34.0 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 March 31, 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 that was placed into service in the fourth quarter of 2013. Our equity investment in the Texas Express NGL system at March 31, 2015 and December 31, 2014, was $380.1 million and $380.6 million, respectively, which is included on our consolidated statements of financial position in “Other assets, net.” For the three-month periods ended March 31, 2015 and 2014, we recognized $5.7 million of equity income and $1.3 million of equity loss, respectively, in “Other income (expense)” on our consolidated statements of income related to our investment in the system.

For the three-month periods ended March 31, 2015 and 2014, we incurred $5.8 million and $5.3 million, 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.

10. COMMITMENTS AND CONTINGENCIES

Environmental Liabilities

We are subject to federal and state laws and regulations relating to the protection of the environment. Environmental risk is inherent to liquid hydrocarbon and natural gas pipeline operations, and we are, at times, subject to environmental cleanup and enforcement actions. We manage this environmental risk through appropriate environmental policies and practices to minimize any impact our operations may have on the environment. To the extent that we are unable to recover payment for environmental liabilities from insurance or other potentially responsible parties, we will be responsible for payment of liabilities arising from environmental incidents associated with the operating activities of our Liquids and Natural Gas businesses. Our General Partner has agreed to indemnify us from and against any costs relating to environmental liabilities associated with the Lakehead system assets prior to the transfer of these assets to us in 1991. This excludes any liabilities resulting from a change in laws after such transfer. We continue to voluntarily investigate past leak sites on our systems for the purpose of assessing whether any remediation is required in light of current regulations.

As of March 31, 2015 and December 31, 2014, we had $125.4 million and $141.7 million, respectively, included in “Environmental liabilities,” and $67.7 million and $60.1 million, respectively, included in “Other long-term liabilities,” 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 commenced. 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 March 31, 2015 and December 31, 2014, we had a remaining estimated liability of $0.7 million.

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. 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 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. On February 12, 2015, the EPA approved with modifications the Submerged Oil Recovery and Assessment workplan, or SORA, and acknowledged that we had completed the dredging requirements of the Order. At this time, we have completed the SORA.

As of March 31, 2015, regulatory authority has transferred from the EPA to the Michigan Department of Environmental Quality, or MDEQ. We are now working with the MDEQ who 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.

As of March 31, 2015 and December 31, 2014, our total cost estimate for the Line 6B crude oil release is $1.2 billion.

For purposes of estimating our expected losses associated with the Line 6B crude oil release, we have included those costs that we considered probable and that could be reasonably estimated at March 31, 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	$ 1,208.0

For the three-month periods ended March 31, 2015 and 2014, we made payments of $7.8 million and $41.8 million, respectively, for costs associated with the Line 6B crude oil release. As of March 31, 2015 and December 31, 2014, we had a remaining estimated liability of $186.4 million and $195.2 million, respectively.

Line 6B Fines and Penalties

At March 31, 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. Discussions with governmental agencies regarding fines, penalties, and injunctive relief are ongoing.

Insurance Recoveries

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 March 31, 2015, costs related to Line 6B exceeded the limits of the coverage available under this insurance policy. As of March 31, 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. 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 has renewed its comprehensive property and liability insurance programs, which are effective May 1, 2015 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 six actions or claims are pending against us and our affiliates in state and federal courts in connection with the Line 6B crude oil release, including direct actions and actions seeking class status. 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.

11. 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 through 2020 in accordance with our risk management policies. Our derivative instruments that qualify for hedge accounting under authoritative guidance are classified as cash flow hedges.

Derivative Positions

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

	March 31, 2015	December 31, 2014
	(in millions)	
Other current assets [1]	$ 152.8	$ 185.5
Other assets, net	76.4	93.3
Accounts payable and other [2]	(362.2)	(315.4)
Other long-term liabilities	(180.0)	(124.6)
Due from general partner and affiliates	0.1	0.3
	$ (312.9)	$ (160.9)

(1) Includes $0.7 million of cash collateral posted at March 31, 2015.
(2) Includes $22.6 million and $28.4 million held of cash collateral at March 31, 2015 and December 31, 2014, respectively.

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

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-month period ended March 31, 2015, we recognized in interest expense unrealized gains for hedge ineffectiveness of approximately $26.0 million 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 three-month period ended March 31, 2014. We had no similar terminations of our cash flow hedges for the three-month period ended March 31, 2015.

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

	March 31, 2015	December 31, 2014
	(in millions)	
Counterparty Credit Quality [1]		
AAA	$ 0.4	$ 0.1
AA [2]	(94.0)	(49.8)
A	(225.9)	(129.1)
Lower than A [3]	6.6	17.9
	$ (312.9)	$ (160.9)

(1) As determined by nationally-recognized statistical ratings organizations.
(2) Includes $22.6 million and $28.4 million held of cash collateral at March 31, 2015 and December 31, 2014, respectively.
(3) Includes $0.7 million of cash collateral posted at March 31, 2015.

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 March 31, 2015, we held $22.6 million and posted $0.7 million of cash collateral on our asset and liability exposures, respectively. At December 31, 2014, we held $28.4 million of cash collateral on our asset exposures. 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 (1) letters of credit, which are not reflected above, or (2) posting cash collateral, as reflected above.

We have provided letters of credit totaling $359.6 million and $329.6 million relating to our liability exposures pursuant to the margin thresholds in effect at March 31, 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 March 31, 2015, we would have been required to provide additional letters of credit in the amount of $54.6 million.

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

	March 31, 2015	December 31, 2014
	(in millions)	
United States financial institutions and investment banking entities [1]	$ (232.5)	$ (147.1)
Non-United States financial institutions [2]	(108.4)	(54.2)
Other	28.0	40.4
	$ (312.9)	$ (160.9)

(1) Includes $22.6 million and $28.4 million held of cash collateral at March 31, 2015 and December 31, 2014, respectively.
(2) Includes $0.7 million posted of cash collateral at March 31, 2015.

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

Effect of Derivative Instruments on the Consolidated Statements of Financial Position

		Asset Derivatives Fair Value at		Liability Derivatives Fair Value at	
	Financial Position Location	March 31, 2015	December 31, 2014	March 31, 2015	December 31, 2014
		(in millions)			
Derivatives designated as hedging instruments: [1]					
Interest rate contracts	Other current assets [2]	$ —	$ —	$ —	$ —
Interest rate contracts	Accounts payable and other	—	—	(300.5)	(241.0)
Interest rate contracts	Other long-term liabilities	—	—	(159.1)	(102.0)
Commodity contracts	Other current assets	20.7	26.1	—	—
Commodity contracts	Other assets	—	2.1	—	—
		20.7	28.2	(459.6)	(343.0)
Derivatives not designated as hedging instruments:					
Commodity contracts	Other current assets	131.4	159.4	—	—
Commodity contracts	Other assets	76.4	91.2	—	—
Commodity contracts	Accounts payable and other [3]	—	—	(39.1)	(46.0)
Commodity contracts	Other long-term liabilities	—	—	(20.9)	(22.6)
Commodity contracts	Due from general partner and affiliates	0.1	0.3	—	—
		207.9	250.9	(60.0)	(68.6)
Total derivative instruments		$ 228.6	$ 279.1	$ (519.6)	$ (411.6)

(1) Includes items currently designated as hedging instruments. Excludes the portion of de-designated hedges which may have a component remaining in AOCI.
(2) Asset derivatives exclude $0.7 million of cash collateral posted at March 31, 2015.
(3) Liability derivatives exclude $22.6 million and $28.4 million held of cash collateral at March 31, 2015 and December 31, 2014, respectively.

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 March 31, 2015, are unrecognized losses of approximately $26.5 million associated with derivative financial instruments that qualified for and were classified as cash flow hedges of forecasted transactions that were subsequently de-designated, settled, or terminated. These losses are reclassified to earnings over the periods during which the originally hedged forecasted transactions affect earnings.

During the three-month period ended March 31, 2015 and 2014, unrealized commodity hedge gains of $0.6 million and losses of $0.1 million, respectively, were de-designated as a result of the hedges no longer meeting hedge accounting criteria. We estimate that approximately $284.2 million, representing unrealized net losses from our cash flow hedging activities based on pricing and positions at March 31, 2015, will be reclassified from AOCI to earnings during the next 12 months.

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

Derivatives in Cash Flow Hedging Relationships	Amount of Gain (Loss) Recognized in AOCI on Derivative (Effective Portion)	Location of Gain (Loss) Reclassified from AOCI to Earnings (Effective Portion)	Amount of Gain (Loss) Reclassified from AOCI to Earnings (Effective Portion)	Location of Gain (Loss) Recognized in Earnings on Derivative (Ineffective Portion and Amount Excluded from Effectiveness Testing) [1]	Amount of Gain (Loss) Recognized in Earnings on Derivative (Ineffective Portion and Amount Excluded from Effectiveness Testing) [1]
		(in millions)			
For the three-month period ended March 31, 2015					
Interest rate contracts	$ (145.2)	Interest expense	$ (5.4)	Interest expense	$ 28.7
Commodity contracts	(3.6)	Commodity Costs	8.4	Commodity Costs	(4.0)
Total	$ (148.8)		$ 3.0		$ 24.7
For the three-month period ended March 31, 2014					
Interest rate contracts	$ (71.7)	Interest expense	$ (4.7)	Interest expense	$ (5.7)
Commodity contracts	(0.1)	Commodity Costs	(6.5)	Commodity Costs	1.7
Total	$ (71.8)		$ (11.2)		$ (4.0)

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

Components of Accumulated Other Comprehensive Income/(Loss)

	Cash Flow Hedges	
	2015	2014
	(in millions)	
Balance at January 1,	$(211.4)	$ (76.6)
Other Comprehensive Income before reclassifications [1]	(145.1)	(80.0)
Amounts reclassified from AOCI [2] [3]	(1.0)	10.0
Net other comprehensive loss	$(146.1)	$ (70.0)
Balance at March 31,	$(357.5)	$(146.6)

(1) Excludes NCI gain of $1.3 million and loss of $1.2 million reclassified from AOCI at March 31, 2015 and 2014, respectively.
(2) Excludes NCI loss of $2.0 million and gain of $1.2 million reclassified from AOCI at March 31, 2015 and 2014, respectively.
(3) For additional details on the amounts reclassified from AOCI, reference the *Reclassifications from Accumulated Other Comprehensive Income* table below.

Reclassifications from Accumulated Other Comprehensive Income

	For the three-month period ended March 31,	
	2015	2014
	(in millions)	
Losses (gains) on cash flow hedges:		
Interest Rate Contracts [1]	$ 5.4	$ 4.7
Commodity Contracts [2] [3]	(6.4)	5.3
Total Reclassifications from AOCI	$ (1.0)	$ 10.0

(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 $2.0 million and gain of $1.2 million reclassified from AOCI for three-month periods ending March 31, 2015 and 2014, respectively.

Effect of Derivative Instruments on Consolidated Statements of Income

Derivatives Not Designated as Hedging Instruments	Location of Gain or (Loss) Recognized in Earnings [1]	For the three-month period ended March 31, 2015	2014
		Amount of Gain or (Loss) Recognized in Earnings [2] (in millions)	
Interest rate contracts	Interest expense	$ —	$ —
Commodity contracts	Transportation and other services [3]	2.7	(2.1)
Commodity contracts	Commodity sales	(17.3)	—
Commodity contracts	Commodity sales—affiliate	(0.2)	0.4
Commodity contracts	Commodity costs [4]	7.1	(8.8)
Commodity contracts	Power	—	0.3
Other contracts	Other income/(expense)	5.0	2.8
Total		$ (2.7)	$ (7.4)

(1) 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.
(2) Does not include settlements associated with derivative instruments that settle through physical delivery.
(3) Includes settlement gains of $6.6 million and $0.4 million for the three-month periods ended March 31, 2015 and 2014, respectively.
(4) Includes settlement gains (losses) of $25.7 million and ($8.5) million for the three-month periods ended March 31, 2015 and 2014, respectively.

We record the fair market value of our derivative financial and physical instruments in the consolidated statements of financial position as current and long-term assets or liabilities on a gross basis. However, the terms of the ISDA, which governs our financial contracts and our other master netting agreements, allow the parties to elect in respect of all transactions under the agreement, in the event of a default and upon notice to the defaulting party, for the non-defaulting party to set-off all settlement payments, collateral held and any other obligations (whether or not then due), which the non-defaulting party owes to the defaulting party. The effect of the rights of set-off are outlined below.

Offsetting of Financial Assets and Derivative Assets

As of March 31, 2015	Gross Amount of Recognized Assets	Gross Amount Offset in the Statement of Financial Position	Net Amount of Assets Presented in the Statement of Financial Position (in millions)	Gross Amount Not Offset in the Statement of Financial Position [1] [2]	Net Amount
Description:					
Derivatives	$ 229.3	$ —	$ 229.3	$ (77.2)	$152.1

As of December 31, 2014	Gross Amount of Recognized Assets	Gross Amount Offset in the Statement of Financial Position	Net Amount of Assets Presented in the Statement of Financial Position (in millions)	Gross Amount Not Offset in the Statement of Financial Position [1]	Net Amount
Description:					
Derivatives	$ 279.1	$ —	$ 279.1	$ (91.8)	$187.3

(1) Includes $22.6 million and $28.4 million of cash collateral held at March 31, 2015 and December 31, 2014, respectively.
(2) Includes $0.7 million of cash collateral posted at March 31, 2015.

Offsetting of Financial Liabilities and Derivative Liabilities

	As of March 31, 2015				
	Gross Amount of Recognized Liabilities (1)	Gross Amount Offset in the Statement of Financial Position	Net Amount of Liabilities Presented in the Statement of Financial Position (in millions)	Gross Amount Not Offset in the Statement of Financial Position (1) (2)	Net Amount
Description:					
Derivatives	$ (542.2)	$ —	$ (542.2)	$ 77.2	$(465.0)

	As of December 31, 2014				
	Gross Amount of Recognized Liabilities (1)	Gross Amount Offset in the Statement of Financial Position	Net Amount of Liabilities Presented in the Statement of Financial Position (in millions)	Gross Amount Not Offset in the Statement of Financial Position (1)	Net Amount
Description:					
Derivatives	$ (440.0)	$ —	$ (440.0)	$ 91.8	$(348.2)

(1) Includes $22.6 million and $28.4 million of cash collateral at March 31, 2015 and December 31, 2014, respectively.
(2) Includes $0.7 million of cash collateral posted at March 31, 2015.

Inputs to Fair Value Derivative Instruments

The following table sets forth by level within the fair value hierarchy our financial assets and liabilities that were accounted for at fair value on a recurring basis as of March 31, 2015 and December 31, 2014. We classify financial assets and liabilities in their entirety based on the lowest level of input that is significant to the fair value measurement. Our assessment of the significance of a particular input to the fair value measurement requires judgment and may affect our valuation of the financial assets and liabilities and their placement within the fair value hierarchy.

	March 31, 2015					December 31, 2014				
	Level 1	Level 2	Level 3	Collateral	Total	Level 1	Level 2	Level 3	Collateral	Total
					(in millions)					
Interest rate contracts	$ —	$(459.6)	$ —	$ —	$(459.6)	$ —	$(343.0)	$ —	$ —	$(343.0)
Commodity contracts:										
Financial	—	31.8	30.3	—	62.1	—	41.6	42.7	—	84.3
Physical	—	—	7.0	—	7.0	—	—	19.5	—	19.5
Commodity options	—	—	99.5	—	99.5	—	—	106.7	—	106.7
	—	(427.8)	136.8	—	(291.0)	—	(301.4)	168.9	—	(132.5)
Cash collateral	—	—	—	(21.9)	(21.9)	—	—	—	(28.4)	(28.4)
Total	$ —	$(427.8)	$136.8	$ (21.9)	$(312.9)	$ —	$(301.4)	$168.9	$ (28.4)	$(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.

Quantitative Information About Level 3 Fair Value Measurements

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

(1) Prices are in dollars per Millions of British Thermal Units, or MMBtu, for Natural Gas; dollars per Gallon, or Gal, for NGLs; and dollars per barrel, or Bbl, for Crude Oil.
(2) Fair values include credit valuation adjustments of approximately $0.8 million of losses.

Quantitative Information About Level 3 Fair Value Measurements

Contract Type	Fair Value at December 31, 2014 [(2)] (in millions)	Valuation Technique	Unobservable Input	Range [(1)] Lowest	Highest	Weighted Average	Units
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	$ 168.9						

(1) Prices are in dollars per MMBtu for Natural Gas, Gal for NGLs and Bbl for Crude Oil.
(2) Fair values include credit valuation adjustments of approximately $1.0 million of losses.

Level 3 Fair Value Reconciliation

The table below provides a reconciliation of changes in the fair value of our Level 3 financial assets and liabilities measured on a recurring basis from January 1, 2015 to March 31, 2015. No transfers of assets between any of the Levels occurred during the period.

	Commodity Financial Contracts	Commodity Physical Contracts (in millions)	Commodity Options	Total
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	—	1.5	—	1.5
Reported in Commodity costs	0.2	4.9	4.0	9.1
Gains or losses included in other comprehensive income:				
Reported in Other comprehensive income (loss), net of tax	(1.4)	—	—	(1.4)
Purchases, issuances, sales and settlements:				
Purchases	—	—	—	—
Sales	—	—	—	—
Settlements [(2)]	(11.2)	(18.9)	(11.2)	(41.3)
Ending balance as March 31, 2015	$ 30.3	$ 7.0	$ 99.5	$136.8
Amounts reported in Commodity sales	$ —	$ (17.5)	$ —	$ (17.5)
Amount of changes in net assets attributable to the change in derivative gains or losses related to assets and liabilities still held at the reporting date:				
Reported in Commodity sales	$ —	$ 2.6	$ —	$ 2.6
Reported in Commodity costs	2.2	3.1	7.7	13.0

(1) Our policy is to recognize transfers as of the last day of the reporting period.
(2) Settlements represent the realized portion of forward contracts.

Fair Value Measurements of Commodity Derivatives

The following table provides summarized information about the fair values of expected cash flows of our outstanding commodity based swaps and physical contracts at March 31, 2015 and December 31, 2014.

	At March 31, 2015						At December 31, 2014	
			Wtd. Average Price (2)		Fair Value (3)		Fair Value (3)	
	Commodity	Notional (1)	Receive	Pay	Asset	Liability	Asset	Liability
Portion of contracts maturing in 2015								
Swaps								
Receive variable/pay fixed	Natural Gas	1,541,324	$ 2.61	$ 2.98	$ —	$ (0.6)	$ —	$ (0.7)
	NGL	504,250	$ 33.12	$ 40.52	$ 0.1	$ (3.8)	$ —	$ (6.8)
	Crude Oil	739,750	$ 52.35	$ 83.30	$ —	$ (22.9)	$ —	$ (27.4)
Receive fixed/pay variable	Natural Gas	1,728,938	$ 2.91	$ 2.71	$ 0.4	$ —	$ 3.7	$ —
	NGL	1,550,500	$ 46.19	$ 31.00	$24.0	$ (0.5)	$ 39.2	$ —
	Crude Oil	1,303,025	$ 93.91	$ 52.60	$53.8	$ —	$ 65.0	$ —
Receive variable/pay variable	Natural Gas	68,310,000	$ 2.56	$ 2.54	$ 2.6	$ (1.5)	$ 1.5	$ (1.7)
Physical Contracts								
Receive variable/pay fixed	Natural Gas	155,150	$ 2.39	$ 2.19	$ —	$ —	$ —	$ —
	NGL	80,000	$ 32.76	$ 41.89	$ —	$ (0.7)	$ —	$ (3.6)
	Crude Oil	11,000	$ 48.18	$ 51.64	$ —	$ —	$ —	$ —
Receive fixed/pay variable	Natural Gas	406,373	$ 2.46	$ 2.51	$ —	$ —	$ —	$ —
	NGL	398,525	$ 26.68	$ 21.93	$ 1.9	$ (0.1)	$ 19.8	$ —
	Crude Oil	109,000	$ 52.59	$ 50.02	$ 0.3	$ —	$ 0.5	$ —
Receive variable/pay variable	Natural Gas	192,448,455	$ 2.61	$ 2.61	$ 1.6	$ (0.5)	$ 2.2	$ (1.0)
	NGL	10,861,860	$ 18.50	$ 18.15	$ 3.9	$ (0.1)	$ 3.7	$ (1.0)
	Crude Oil	654,682	$ 46.53	$ 47.97	$ 1.0	$ (1.9)	$ 0.3	$ (1.7)
Portion of contracts maturing in 2016								
Swaps								
Receive variable/pay fixed	Natural Gas	363,514	$ 2.75	$ 3.41	$ —	$ (0.2)	$ —	$ (0.1)
	Crude Oil	415,950	$ 58.02	$ 82.69	$ —	$ (10.2)	$ —	$ (8.1)
Receive fixed/pay variable	Natural Gas	465,600	$ 3.32	$ 3.16	$ 0.1	$ —	$ —	$ —
	NGL	823,500	$ 39.64	$ 27.63	$ 9.8	$ —	$ 9.3	$ —
	Crude Oil	415,950	$ 85.08	$ 58.02	$11.2	$ —	$ 9.1	$ —
Receive variable/pay variable	Natural Gas	44,959,000	$ 2.93	$ 2.91	$ 2.0	$ (1.1)	$ 0.5	$ (0.3)
Physical Contracts								
Receive fixed/pay variable	Natural Gas	63,591	$ 3.12	$ 2.98	$ —	$ —	$ —	$ —
	NGL	4,398	$ 29.86	$ 25.91	$ —	$ —	$ —	$ —
Receive variable/pay variable	Natural Gas	59,944,569	$ 3.05	$ 3.04	$ 0.9	$ (0.4)	$ 0.7	$ (0.4)
	NGL	8,944,071	$ 18.00	$ 17.89	$ 0.9	$ —	$ —	$ —
Portion of contracts maturing in 2017								
Swaps								
Receive variable/pay fixed	Natural Gas	24,030	$ 3.24	$ 3.48	$ —	$ —	$ —	$ —
	NGL	547,500	$ 23.81	$ 25.86	$ —	$ (1.1)	$ —	$ —
	Crude Oil	547,500	$ 61.30	$ 66.72	$ —	$ (2.9)	$ —	$ —
Receive fixed/pay variable	NGL	547,500	$ 23.59	$ 23.81	$ 0.3	$ (0.5)	$ 0.7	$ —
	Crude Oil	547,500	$ 66.78	$ 61.30	$ 2.9	$ —	$ 0.8	$ —
Receive variable/pay variable	Natural Gas	2,700,000	$ 3.44	$ 3.37	$ 0.2	$ —	$ —	$ —
Physical Contracts								
Receive variable/pay variable	Natural Gas	28,047,550	$ 3.36	$ 3.35	$ 0.3	$ (0.1)	$ 0.2	$ (0.1)
Portion of contracts maturing in 2018								
Physical Contracts								
Receive variable/pay variable	Natural Gas	5,787,810	$ 3.57	$ 3.56	$ 0.1	$ —	$ —	$ —
Portion of contracts maturing in 2019								
Physical Contracts								
Receive variable/pay variable	Natural Gas	2,187,810	$ 3.56	$ 3.53	$ 0.1	$ —	$ —	$ —
Portion of contracts maturing in 2020								
Physical Contracts								
Receive variable/pay variable	Natural Gas	359,640	$ 3.88	$ 3.85	$ —	$ —	$ —	$ —

(1) Volumes of natural gas are measured in MMBtu, whereas volumes of NGL and crude oil are measured in Bbl.
(2) Weighted average prices received and paid are in $/MMBtu for natural gas and $/Bbl for NGL and crude oil.
(3) The fair value is determined based on quoted market prices at March 31, 2015 and December 31, 2014, respectively, discounted using the swap rate for the respective periods to consider the time value of money. Fair values are presented in millions of dollars and exclude credit valuation adjustments of approximately $0.2 million of losses and $0.5 million of losses at March 31, 2015 and December 31, 2014, respectively, and cash collateral received.

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

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

(1) Volumes of natural gas are measured in MMBtu, whereas volumes of NGL and crude oil are measured in Bbl.
(2) Strike and market prices are in $/MMBtu for natural gas and in $/Bbl for NGL and crude oil.
(3) The fair value is determined based on quoted market prices at March 31, 2015 and December 31, 2014, respectively, discounted using the swap rate for the respective periods to consider the time value of money. Fair values are presented in millions of dollars and exclude credit valuation adjustments of approximately $0.6 million and $0.7 million of losses at March 31, 2015 and December 31, 2014, respectively, as well as cash collateral received.

Fair Value Measurements of Interest Rate Derivatives

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

Date of Maturity & Contract Type	Accounting Treatment	Notional	Average Fixed Rate (1)	Fair Value (2) at March 31, 2015	Fair Value (2) at 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%	$ (13.2)	$ (12.9)
Contracts maturing in 2018					
Interest Rate Swaps—Pay Fixed	Cash Flow Hedge	$ 810	2.24%	$ (5.3)	$ (1.3)
Contracts maturing in 2019					
Interest Rate Swaps—Pay Fixed	Cash Flow Hedge	$ 620	2.96%	$ (5.6)	$ (3.3)
Contracts settling prior to maturity					
2015—Pre-issuance Hedges	Cash Flow Hedge	$1,000	5.48%	$ (295.3)	$ (258.3)
2016—Pre-issuance Hedges	Cash Flow Hedge	$ 500	4.21%	$ (80.0)	$ (63.4)
2017—Pre-issuance Hedges	Cash Flow Hedge	$ 500	3.69%	$ (51.1)	$ (36.0)
2018—Pre-issuance Hedges	Cash Flow Hedge	$ 350	3.08%	$ (14.6)	$ (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 March 31, 2015 and December 31, 2014, respectively, discounted using the swap rate for the respective periods to consider the time value of money. Fair values exclude credit valuation adjustments of approximately $5.6 million of gains at March 31, 2015 and $37.4 million of gains at December 31, 2014, and cash collateral posted.

12. INCOME TAXES

We are not a taxable entity for United States federal income tax purposes, or for the majority of states that impose an income tax. Taxes on our net income generally are borne by our unitholders through the allocation of taxable income. Our income tax expense results from the enactment of state income tax laws by the State of Texas that apply to entities organized as partnerships. Our income tax expense is based upon many but not all items included in net income.

We computed our income tax expense by applying a Texas state income tax rate to modified gross margin. Our Texas state income tax rate was 0.4% for the three-month periods ended March 31, 2015 and 2014. Our income tax expense is $2.4 million and $2.0 million for the three-month periods ended March 31, 2015 and 2014, respectively.

At March 31, 2015 and December 31, 2014, we included a current income tax payable of $2.1 million and $1.5 million, respectively, in “Property and other taxes payable” on our consolidated statements of financial position. In addition, at March 31, 2015 and December 31, 2014, we included a deferred income tax payable of $22.8 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.

13. SEGMENT INFORMATION

Our business is divided into operating segments, defined as components of the enterprise, about which financial information is available and evaluated regularly by our Chief Operating Decision Maker, collectively comprised of our senior management, in deciding how resources are allocated and performance is assessed.

Each of our reportable segments is a business unit that offers different services and products that 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:

	As of and for the three-month period ended March 31, 2015			
	Liquids	Natural Gas	Corporate [1]	Total
	(in millions)			
Operating revenues: [2]				
Commodity sales	$ —	$ 822.7	$ —	$ 822.7
Transportation and other services	555.1	50.8	—	605.9
	555.1	873.5	—	1,428.6
Commodity costs	—	779.1	—	779.1
Environmental costs, net of recoveries	0.8	—	—	0.8
Operating and administrative	130.4	82.7	4.0	217.1
Power	63.6	—	—	63.6
Depreciation and amortization	90.1	38.3	—	128.4
	284.9	900.1	4.0	1,189.0
Operating income (loss)	270.2	(26.6)	(4.0)	239.6
Interest expense, net	—	—	48.3	48.3
Allowance for equity used during construction	—	—	23.0	23.0
Other income	—	5.7[3]	0.2	5.9
Income (loss) before income tax expense	270.2	(20.9)	(29.1)	220.2
Income tax expense	—	—	2.4	2.4
Net income (loss)	270.2	(20.9)	(31.5)	217.8
Less: Net income attributable to:				
Noncontrolling interest	—	—	51.3	51.3
Series 1 preferred unit distributions	—	—	22.5	22.5
Accretion of discount on Series 1 preferred units	—	—	3.9	3.9
Net income (loss) attributable to general and limited partner ownership interests in Enbridge Energy Partners, L.P.	$ 270.2	$ (20.9)	$ (109.2)	$ 140.1
Total assets	$12,143.3	$ 5,482.9 [4]	$ 430.5	$18,056.7
Capital expenditures (excluding acquisitions)	$ 456.3	$ 55.5	$ —	$ 511.8

(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-month period ended March 31, 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 includes $380.1 million for our long term equity investment in the Texas Express NGL system.

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	As of and for the three-month period ended March 31, 2014			
	Liquids	Natural Gas	Corporate (1)	Total
	(in millions)			
Operating revenues:				
Commodity sales	$ —	$ 1,599.5	$ —	$ 1,599.5
Transportation and other services	432.7	47.4	—	480.1
	432.7	1,646.9(2)	—	2,079.6
Commodity costs	—	1,488.7	—	1,488.7
Environmental costs, net of recoveries	5.0	—	—	5.0
Operating and administrative	108.4	108.9	(0.3)	217.0
Power	50.4	—	—	50.4
Depreciation and amortization	66.8	37.0	—	103.8
	230.6	1,634.6	(0.3)	1,864.9
Operating income	202.1	12.3	0.3	214.7
Interest expense, net	—	—	76.9	76.9
Allowance for equity used during construction	—	—	20.7	20.7
Other income (expense)	—	(1.3) (3)	0.5	(0.8)
Income (loss) before income tax expense	202.1	11.0	(55.4)	157.7
Income tax expense	—	—	2.0	2.0
Net income (loss)	202.1	11.0	(57.4)	155.7
Less: Net income attributable to				
Noncontrolling interest	—	—	36.3	36.3
Series 1 preferred unit distributions	—	—	22.5	22.5
Accretion of discount on Series 1 preferred units	—	—	3.6	3.6
Net income (loss) attributable to general and limited partner ownership interests in Enbridge Energy Partners, L.P.	$ 202.1	$ 11.0	$ (119.8)	$ 93.3
Total assets	$9,854.0	$ 5,194.9(4)	$ 304.0	$15,352.9
Capital expenditures (excluding acquisitions)	$ 495.0	$ 50.2	$ 5.3	$ 550.5

(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) Total segment revenue and intersegment revenue for the natural gas segment for the three-month period ended March 31, 2014 was corrected to eliminate intra-segment revenue of $318.7 million that was recorded in error and previously reported on our Quarterly Report on Form 10-Q for the three-month period ended March 31, 2014. This error did not impact previously reported segment operating revenue or consolidated operating revenue for the three-month period ended March 31, 2014.

(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 includes $375.7 million for our long term equity investment in the Texas Express NGL system.

14. 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 three-month period ended March 31,	
	2015	2014
	(in millions)	
Additions to property, plant and equipment	$ 460.0	$ 612.8
Increase (decrease) in construction payables	51.8	(62.3)
Total capital expenditures (excluding “Investment in joint venture”)	$ 511.8	$ 550.5

15. 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 FERC’s 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 calendar year, less any amortizations, and the cumulative over and under recovery revenue adjustments made during the current calendar 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-month periods ended March 31, 2015 and 2014 are as follows:

	For the three-month period ended March 31,	
	2015	2014
	(in millions)	
Net regulatory asset balance at beginning of period	$ 6.0	$ 7.7
Current year (over)/under recovery revenue adjustments	(9.1)	2.3
Amortization of prior year regulatory asset	(3.7)	(1.9)
Net regulatory asset (liability) balance at end of period	$ (6.8)	$ 8.1

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 March 31, 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-month period ended March 31, 2014, we amortized through revenue $2.1 million 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.

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 March 31, 2015 and December 31, 2014, we had $4.5 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-month periods ended March 31, 2015 and 2014, we amortized through revenue $1.4 million and $1.7 million of property tax over recovery liabilities, respectively, on our consolidated statements of income with a corresponding amount reducing the contractual obligation on our consolidated statements of financial position.

Allowance for Equity Used During Construction

We are permitted to capitalize and recover costs for rate-making purposes that include an allowance for equity costs during construction, referred to as AEDC. In connection with construction of the Eastern Access Projects, Line 3 Replacement, Line 6B 75-mile Replacement and Mainline Expansion Projects, we recorded $23.0 million and $20.7 million of “Allowance for equity used during construction” in our consolidated statement of income for the three-month periods ended March 31, 2015 and 2014, respectively, and a corresponding amount in “Property, plant and equipment” on our consolidated statement of financial position at March 31, 2015 and 2014, respectively.

16. RECENT ACCOUNTING PRONOUNCEMENTS NOT YET ADOPTED

Revenues from Contracts with Customers

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

Going Concern Uncertainties

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

Consolidation

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

Debt Issuance Costs

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

17. SUBSEQUENT EVENTS

Distribution to Partners

On April 30, 2015, the board of directors of Enbridge Management declared a distribution payable to our partners on May 15, 2015. The distribution will be paid to unitholders of record as of May 8, 2015 of our available cash of $249.9 million at March 31, 2015, or $0.5700 per limited partner unit. Of this distribution, $209.6 million will be paid in cash, $39.5 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.

Distribution to Series EA Interests

On April 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 $52.3 million to the noncontrolling interest in the Series EA, while $17.5 million will be paid to us.

Distribution to Series ME Interests

On April 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 $4.5 million to the noncontrolling interest in the Series ME, while $1.5 million will be paid to us.

Distribution from MEP

On April 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 May 15, 2015. The distribution will be paid to unitholders of record as of May 8, 2015, of MEP's available cash of $16.0 million at March 31, 2015, or $0.3475 per limited partner unit. MEP will pay $7.4 million to their public Class A common unitholders, while $8.6 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 April 29, 2015, the general partner of Midcoast Operating declared a cash distribution by Midcoast Operating payable to its partners of record as of May 8, 2015. Midcoast Operating will pay $26.0 million to us and $27.8 million to MEP.

Item 2. Management’s Discussion and Analysis of Financial Condition and Results of Operations

The following discussion and analysis of our financial condition and results of operations is based on and should be read in conjunction with our consolidated financial statements and the accompanying notes included in Item 1. *Financial Statements* of this report and in conjunction with the audited consolidated financial statements and accompanying footnotes in our Annual Report on Form 10-K for the year ended December 31, 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. Additionally, we realize incremental revenue on gas purchased at the wellhead, increase pipeline utilization and provide other services that are valued by our customers. The 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-month periods ended March 31, 2015 and 2014.

	For the three-month period ended March 31, 2015	2014
	(in millions)	
Operating income (loss)		
Liquids	$ 270.2	$ 202.1
Natural Gas	(26.6)	12.3
Corporate, operating and administrative	(4.0)	0.3
Total operating income	239.6	214.7
Interest expense	48.3	76.9
Allowance for equity used during construction	23.0	20.7
Other income (expense)	5.9	(0.8)
Income before income tax expense	220.2	157.7
Income tax expense	2.4	2.0
Net income	217.8	155.7
Less: Net income attributable to:		
Noncontrolling interest	51.3	36.3
Series 1 preferred unit distributions	22.5	22.5
Accretion of discount on Series 1 preferred units	3.9	3.6
Net income attributable to general and limited partner ownership interests in Enbridge Energy Partners, L.P.	$ 140.1	$ 93.3

Highlights

Liquids

Our Liquids segment operating income increased $68.1 for the three-month period ended March 31, 2015 as compared to the same period 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. Furthermore, average daily volumes delivered on our liquids systems increased 415,000 Bpd for the three-month period ended March 31, 2015 when compared to the same period in 2014.

Natural Gas

Our Natural Gas segment operating income decreased $38.9 million for the three-month period ended March 31, 2015 as compared to the same period in 2014. Natural Gas segment operating income decreased primarily due to reduced segment gross margin, which was greatly impacted by the current pricing environment, which may continue through 2015 and into 2016. The most significant reduction to segment gross margin was due to increased non-cash, mark-to-market net losses of $39.7 million coupled with a $17.4 million decline in natural gas pricing differentials for the three-month period ended March 31, 2015 when compared to the same period in 2014. These decreases in segment gross margin were slightly offset by increased production volumes and workforce and other cost reductions for the three-month period ended March 31, 2015 when compared to the same period in 2014.

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-month period ended March 31, 2015	2014
	(in millions)	
Liquids segment:		
Non-qualified hedges	$ (3.9)	$ (2.2)
Natural Gas segment:		
Hedge ineffectiveness	(4.0)	1.7
Non-qualified hedges	(31.1)	2.9
Commodity derivative fair value net gains (losses)	(39.0)	2.4
Corporate:		
Interest rate hedge ineffectiveness	28.7	(5.7)
Non-qualified interest rate hedges	—	—
Derivative fair value net gains (losses)	$ (10.3)	$ (3.3)

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-month period ended March 31,	
	2015	2014
	(in millions)	
Operating Results:		
Operating revenue	$ 555.1	$ 432.7
Environmental costs, net of recoveries	0.8	5.0
Operating and administrative	130.4	108.4
Power	63.6	50.4
Depreciation and amortization	90.1	66.8
Operating expenses	284.9	230.6
Operating income	$ 270.2	$ 202.1
Operating Statistics		
Lakehead system:		
United States [(1)]	1,899	1,560
Province of Ontario [(1)]	431	440
Total Lakehead system delivery volumes [(1)]	2,330	2,000
Barrel miles (billions)	157	134
Average haul (miles)	750	746
Mid-Continent system delivery volumes [(1)]	199	211
North Dakota system:		
Trunkline [(1)]	340	242
Gathering [(1)]	2	3
Total North Dakota system delivery volumes [(1)]	342	245
Total Liquids segment delivery volumes [(1)]	2,871	2,456

(1) Average barrels per day in thousands.

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

Operating income of our Liquids segment for the three-month period ended March 31, 2015 increased $68.1 million, as compared with the same period in 2014, primarily due to the following reasons discussed below.

Operating revenue of our Liquids segment increased $122.4 million for the three-month period ended March 31, 2015 when compared with the same period in 2014, primarily due to the filing of FERC tariffs to increase the rates for our Lakehead, North Dakota and Ozark systems. These rate increases became effective on April 1, 2014 and July 1, 2014 for our North Dakota and Ozark systems, and August 1, 2014 for our Lakehead system. The increase in rates accounted for $90.5 million of the increase in operating revenue for the three-month period ended March 31, 2015 when compared to the same period in 2014. The increase in rates is primarily due to additional assets placed into service. In 2014, $2.7 billion of additional assets were placed into service on the Lakehead system, including the Eastern Access, Mainline Expansion, and other expansion projects.

Additionally, operating revenue of our Liquids segment increased for the three-month period ended March 31, 2015 when compared with the same period in 2014 by $28.7 million due to increased average daily delivery volumes on our Lakehead and North Dakota systems. Average daily volumes delivered on our liquids systems increased 415,000 Bpd for the three-month period ended March 31, 2015 when compared to the same period in 2014. Of that amount, our Lakehead system realized higher daily volumes of 330,000 Bpd, which contributed to increased revenue of $19.8 million. This increase in volumes is attributable to a combination of increased supply from Western Canada and additional capacity on our system from the assets placed into service during the second half of 2014. The North Dakota system also experienced an increase of 97,000 Bpd as shippers shifted volumes onto our North Dakota system and away from higher cost alternatives such as transportation by rail.

The operating and administrative expenses of our Liquids segment increased $22.0 million for the three-month period ended March 31, 2015 when compared with the same period in 2014, primarily due to cost increases of: $4.3 million of pipeline integrity costs; $4.5 million of workforce related costs; $6.8 million of property taxes; and $7.3 million of other operating and administrative expenses, mainly consisting of contract labor, insurance, rents and lease payments, and professional and regulatory services. The increase in pipeline integrity costs is primarily the result of increased in-line inspections on our systems for the three-month period ended March 31, 2015 when compared with the same period in 2014. The other cost increases primarily resulted from the additional assets placed into service during 2014.

Power costs increased $13.2 million for the three-month period ended March 31, 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 $23.3 million for the three-month period ended March 31, 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 2015, Enbridge announced that it is reviewing a potential restructuring plan that may involve the sale of some of its U.S. liquids pipeline assets to us. The total estimated capital costs or net book value of Enbridge’s U.S. liquids pipeline assets that may ultimately be considered under the potential restructuring plan may exceed $10.0 billion. Enbridge’s U.S. liquids pipeline systems are extensive and include very strategic assets such as the Flanagan South, Spearhead, Seaway, Toledo, and Southern Access Extension pipelines. In addition, we have jointly funded with Enbridge several major expansions of the Lakehead pipeline system in the Great Lakes region of the United States. Enbridge’s review of a potential restructuring plan is underway and has not progressed to a conclusion. In the event that we receive a proposal from Enbridge, the Board of Directors of Enbridge Energy Management, L.L.C., the delegate of the General Partner would appoint a special committee comprised of independent directors to review and consider any such proposal. Acceptance of a proposal is subject to the review and favorable recommendation by the special committee and final approval by the Board.

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 ideal 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 growth. 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	Early 2016	Joint [(3)]
U.S. Mainline Expansions:			
Chicago Area Connectivity (Line 62 twin)	495	Third 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 Inc.
(2) The Sandpiper Project is 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. The Certificate hearings in Minnesota were completed in the first quarter of 2015, and in April 2015, the presiding Administrative Law Judge, or ALJ, recommended that the MNPUC grant approval of the Certificate based on evidence provided by Enbridge that the need for the system has been demonstrated. The ALJ also recommended that no alternative routes to that proposed by Enbridge should be considered in the subsequent Route Permit process. With the ALJ's recommendation, the MNPUC is expected to issue a decision on need in the third quarter of 2015, followed by a separate review of the proposed pipeline route. 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 early 2016. This project is being funded at 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 of the 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. These projects require only the addition of pumping horsepower and crude oil tanks at existing sites with no pipeline construction.

The initial phase of the Line 67 pipeline expansion includes increasing capacity between Neche, North Dakota into the Superior, Wisconsin Terminal from 450,000 Bpd to 570,000 Bpd, which was completed in the third quarter of 2014. The second phase will add an additional 230,000 Bpd of capacity at an estimated cost of approximately $240 million and is expected to be completed in the third quarter of 2015. These projects require only the addition of pumping horsepower at existing sites, with no pipeline construction. Subject to regulatory and other approvals, including an amendment to the current Presidential border crossing permit to allow for operation of the Line 67 pipeline at its currently planned operating capacity of 800,000 Bpd through the border crossing segment, the expansions will be undertaken on a full cost-of-service basis. We continue to work with regulatory authorities; however, the timing of the Federal regulatory approval for the expansion to 800,000 Bpd 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 applicable regulatory approvals.

In November of 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 will expand the pipeline capacity to 800,000 Bpd at a cost of approximately $395 million and is expected to be in service in the second quarter 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. The in-transit merchant storage service will provide shippers the ability to off-load barrels in-transit at Flanagan or Superior, direct them into temporary storage, and later return them to the Lakehead system for delivery to their ultimate destinations, all at the applicable tariff rate from the initial origin point to the ultimate delivery point.

The second tranche of the Southern Access expansion, which remains subject to regulatory and other approvals, 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 third quarter of 2015.

These projects, collectively referred to as the U.S. Mainline Expansions projects, have a remaining cost of approximately $1.9 billion and will be undertaken on a cost-of-service basis. Furthermore, these projects are jointly funded at 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 mechanically 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. In October 2014, the Canadian National Energy Board, or NEB, requested additional information regarding one of the 30 conditions imposed on the Line 9B reversal and Line 9 expansion project in March 2014. 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 two conditions from its previous order and Enbridge filed for the Leave to Open from the NEB. Enbridge expects to place the Line 9B reversal and Line 9 expansion project into service in the second quarter of 2015. As a condition of the February 2015 approval, the NEB also imposed additional obligations to ensure optimal protection of the area's water resources. These projects will enable growing light crude production from the Bakken shale and from Alberta to meet refinery needs in Michigan, Ohio, Ontario and Quebec. These projects will also provide much needed transportation outlets for light crude, mitigating the current discounting of supplies in the basins, while also providing more favorable supply costs to refiners currently dependent on crudes priced off of the Atlantic basin.

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. Subject to regulatory and other approvals, 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-month period ended March 31,	
	2015	2014
	(in millions)	
Operating revenues	$ 873.5	$ 1,646.9
Cost of natural gas	779.1	1,488.7
Operating and administrative	82.7	108.9
Depreciation and amortization	38.3	37.0
Operating expenses	900.1	1,634.6
Operating income (loss)	(26.6)	12.3
Other income (loss)	5.7	(1.3)
Net income (loss)	$ (20.9)	$ 11.0
Operating Statistics (MMBtu/d)		
East Texas	1,007,000	971,000
Anadarko	831,000	824,000
North Texas	287,000	272,000
Total	2,125,000	2,067,000
NGL Production (Bpd)	81,046	80,899

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

The Natural Gas business experienced an operating loss of $26.6 million for the three-month period ended March 31, 2015, compared to the $12.3 million operating income recorded for the same period in 2014, representing a total decrease of $38.9 million in operating income. The area most affected was segment gross margin, which decreased $63.8 million for the three-month period ended March 31, 2015, as compared with the same period in 2014.

Segment gross margin experienced a net decrease of $39.7 million due to non-cash, mark-to-market losses of $35.1 million and gains of $4.6 million for the three-month periods ended March 31, 2015 and March 31, 2014, respectively. These losses are primarily related to the reversal of previously recognized unrealized market-to-market gains as the underlying transactions were settled, partially offset by gains on non-qualifying hedges related to the decrease in commodity prices for the three-month period ended March 31, 2015, as compared with the same period in 2014.

Our segment gross margin was also impacted by decreased margins within our gas marketing function due to price differentials between market centers by approximately $17.4 million for the three-month period ended March 31, 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 $8.8 million for the three-month period ended March 31, 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 $2.9 million for the three-month period ended March 31, 2015, when compared to the same period of 2014, for non-cash charges to decrease the cost basis of our natural gas inventory to net realizable value. Since we hedge our storage positions financially, these charges are recovered when the physical natural gas inventory is sold or the financial hedges are realized.

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

Operating and administrative costs decreased $26.2 million for the three-month period ended March 31, 2015, compared to the same period in 2014, primarily due to workforce reductions in December 2014 which resulted in a decrease in outside contract labor as well as other related benefit costs. In addition, other management cost reduction efforts in late 2014 and during the first quarter in 2015 were undertaken.

Other income was $5.7 million for the three-month period ended March 31, 2015, compared to a $1.3 million expense for the same period in 2014, primarily as a result of increases in equity earnings on our investment in the Texas Express NGL system from higher volumes on the system and increases in demand payments from Texas Express shippers.

Future Prospects for 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 natural gas liquids in combination with core asset optimization, and (4) capitalizing on new market opportunities by diversifying geographically and by commodity composition. We will pursue internal growth projects designed to provide exposure to incremental supplies of natural gas at the wellhead, increase opportunities to serve additional customers, including new wholesale customers, and allow expansion of our treating and processing businesses. Additionally, we will pursue acquisitions to expand our natural gas services in situations where we have natural advantages to create additional value.

Impact of Commodity Prices

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

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 April 2013, we announced plans to construct a cryogenic natural gas processing plant near Beckville in Panola County, Texas, which we refer to as the Beckville Processing Plant. This plant is expected to serve existing and prospective customers pursuing production in the Cotton Valley formation, which is comprised of approximately ten counties in East Texas and has been a steady producer of natural gas for decades, as well as the Eaglebine developments. Production from the Cotton Valley formation typically contains two to three gallons of NGLs per Mcf of natural gas. The region currently produces approximately 2.2 billion cubic feet per day, or Bcf/d, of natural gas with 73,000 Bpd of associated NGLs. Until recently, the primary exploitation method in the Cotton Valley formation has been vertical wells. Lower horizontal drilling costs, coupled with the latest fracturing technology, has brought significant interest back to this area. Economics associated with horizontal wells in the Cotton Valley formation compare favorably to other rich natural gas plays, which has encouraged producers to increase drilling activity in the region. We expect our Beckville processing plant to be capable of processing approximately 150 MMcf/d of natural gas and producing approximately 8,500 Bpd of NGLs to accommodate the additional liquids-rich natural gas being developed within this geographical area in which our East Texas system operates. Related NGL takeaway infrastructure connecting the Beckville plant to third party NGL transportation systems was also constructed. We estimate the cost of constructing the plant to be approximately $155.0 million and expect it to be placed into commercial service in the second quarter of 2015.

The project is funded by us and 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 and Eagle Ford formations. We have a series of projects and an acquisition in this play. We have commenced construction of a lateral and associated facilities that will create gathering capacity of over 50 MMcf/d for rich natural gas to be delivered from Eaglebine production areas to our complex of cryogenic processing facilities in East Texas. The initial facilities are projected to be placed in service by late 2015, with the lateral expected to be in service in mid-2016. Given the proximity of our existing East Texas assets, this expansion into Eaglebine will allow us to offer gathering and processing services while leveraging assets on our existing footprint.

On February 27, 2015, we acquired from 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* under Note 3. *Acquisitions* .

We estimate the aggregate cost of these projects and acquisitions described above to be approximately $160.0 million, of which $135.0 million is estimated to be spent in 2015. Funding is to be provided by us and 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, noncontrolling interest and other costs such as income taxes, which are not allocated to the business segments.

	For the three-month period ended March 31,	
	2015	2014
	(in millions)	
Operating Results:		
Operating and administrative expenses	$ 4.0	$ (0.3)
Operating income (loss)	(4.0)	0.3
Interest expense, net	48.3	76.9
Allowance for equity used during construction	23.0	20.7
Other income	0.2	0.5
Income tax expense	2.4	2.0
Net loss	(31.5)	(57.4)

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

The $25.9 million decrease in our net loss for the three-month period ended March 31, 2015, as compared to the same period in 2014 was primarily attributable to a decrease of $28.6 million in interest expense to $48.3 million for the three-month period ended March 31, 2015, compared with $76.9 million for the corresponding period in 2014. During the three-month period ended March 31, 2015, charges to interest expense from ineffectiveness on hedging instruments decreased by $34.4 million, as compared to the same period in 2014.

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.

As set forth in the following table, we had approximately $1.7 billion of liquidity available to us at March 31, 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.

	EEP	MEP
	(in millions)	
Cash and cash equivalents	$ 276.2	$ 5.3
Total credit available under EEP's Credit Facilities	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	(1,360.0)	—
Amounts outstanding under the EUS 364-day Credit Facility	—	—
Amounts outstanding under MEP's Credit Agreement	—	(315.0)
Principal amount of commercial paper issuances	(777.4)	—
Letters of credit outstanding	(360.2)	—
Total	$ 1,153.6	$ 540.3

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 March 31, 2015, we had a working capital deficit of approximately $0.8 billion and approximately $1.7 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 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.

2015 Issuance Date	Number of Class A common units Issued	Offering Price per Class A common unit	Net Proceeds to the Partnership [1]	General Partner Contribution [2]	Net Proceeds Including General Partner Contribution
		(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.

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

In May 2012, the OLP amended and restated its partnership agreement to establish 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 $36.8 million and $178.5 million to the OLP during the three month periods ended March 31, 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

In December 2012, the OLP further amended and restated its limited partnership agreement to establish another 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 $162.7 million and $74.3 million to the OLP for the three month periods ended March 31, 2015, and 2014, respectively, to fund its equity portion of the construction costs associated with the Mainline Expansion Projects.

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, (i) on a revolving basis for a 364-day period and (ii) for a 364-day term on a non-revolving basis following the expiration of the revolving period. Loans under the EUS 364-day Credit Facility accrue interest 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 March 31, 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 (i) debt or equity securities in a registered public offering, or (ii) 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 $120 million on maintenance capital activities. We expect to receive funding of approximately $0.9 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 $135 million from MPC based on joint funding arrangement on the Sandpiper Project. We made capital expenditures of $0.5 billion for the three-month period ending March 31, 2015, including $19.2 million on maintenance capital activities and $0.2 billion of expenditures that were financed by contributions from our General Partner and MPC via joint funding arrangements. In addition, we incurred $1.9 million in net contributions to fund our joint ventures. At March 31, 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)
Liquids Projects	
Eastern Access Projects	$ 315
U.S. Mainline Expansions	880
Sandpiper	365
Line 3 Replacement	100
Liquids Integrity Program	290
Expansion Capital	140
Maintenance Capital Expenditures	75
	2,165
Less joint funding from:	
General Partner	945
Third parties	135
Liquids Total	**$ 1,085**
Natural Gas Projects	
Beckville Cryogenic Processing Plant	$ 60
Eaglebine Developments	135
Expansion Capital	105
Maintenance Capital Expenditures	45
	345
Less joint funding from:	
MEP	180
Natural Gas Total	**$ 165**
TOTAL	**1,250**

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 three month period ended March 31, 2015, our cash flows were impacted by the approximate $7.8 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.

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

	Notional	2015	2016	2017	2018	2019 & Thereafter	Total (3)
			(in millions)				
Swaps							
Natural gas (1)	120,092,406	$ 0.9	$ 0.8	$ 0.2	$ —	$ —	$ 1.9
NGL (2)	3,973,250	19.8	9.8	(1.3)	—	—	28.3
Crude Oil (2)	3,969,675	30.9	1.0	—	—	—	31.9
Options							
Natural gas—puts purchased (1)	4,672,000	3.5	1.3	—	—	—	4.8
Natural gas—puts written (1)	4,672,000	(3.5)	(1.3)	—	—	—	(4.8)
Natural gas—calls purchased (1)	2,609,500	—	0.1	—	—	—	0.1
Natural gas—calls written (1)	2,609,500	—	(0.1)	—	—	—	(0.1)
NGL—puts purchased (2)	5,116,500	29.3	39.9	1.0	—	—	70.2
NGL—calls written (2)	4,497,750	(0.2)	(2.4)	(1.2)	—	—	(3.8)
Crude Oil—puts purchased (2)	1,902,700	16.0	15.6	5.1	—	—	36.7
Crude Oil—calls written (2)	1,902,700	—	(0.5)	(2.5)	—	—	(3.0)
Forward contracts							
Natural gas (1)	289,400,948	1.1	0.5	0.2	0.1	0.1	2.0
NGL (2)	20,288,854	4.9	0.9	—	—	—	5.8
Crude Oil (2)	774,682	(0.6)	—	—	—	—	(0.6)
Totals		$102.1	$65.6	$ 1.5	$0.1	$ 0.1	$169.4

(1) Notional amounts for natural gas are recorded in MMBtu.
(2) Notional amounts for NGLs and crude oil are recorded in Barrels, or Bbl.
(3) Fair values exclude credit adjustments of approximately $0.8 million of losses at March 31, 2015, and 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 March 31, 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)	$2,020	$ (5.2)	$ (6.9)	$ (5.8)	$ (4.9)	$(1.4)	$ (24.2)
Pre-issuance hedges	$2,350	(295.3)	(80.0)	(51.1)	(14.6)	—	(441.0)
		$(300.5)	$(86.9)	$(56.9)	$(19.5)	$(1.4)	$(465.2)

(1) Fair values exclude credit valuation adjustments of approximately $5.6 million of gains at March 31, 2015.
(2) Excludes $0.7 million of cash collateral posted at March 31, 2015.

Cash Flow Analysis

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

	For the three-month period ended March 31, 2015	2014 (in millions)	Variance 2015 vs. 2014 Increase (Decrease)
Total cash provided by (used in):			
Operating activities	$ 380.5	$ 210.8	$ 169.7
Investing activities	(504.0)	(567.8)	63.8
Financing activities	207.1	394.1	(187.0)
Net increase in cash and cash equivalents	83.6	37.1	46.5
Cash and cash equivalents at beginning of year	197.9	164.8	33.1
Cash and cash equivalents at end of period	$ 281.5	$ 201.9	$ 79.6

Operating Activities

Net cash provided by our operating activities increased $169.7 million for the three-month period ended March 31, 2015 compared to the same period in 2014, primarily due to a increase in our working capital accounts of $81.0 million. This increase, due to our working capital accounts, was coupled with a $62.1 million increase in net income in addition to non-cash items of $22.5 million for the three-month period ended March 31, 2015 as compared to the same period in 2014.

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

	For the three-month period ended March 31, 2015	2014 (in millions)	Variance 2015 vs. 2014
Changes in operating assets and liabilities, net of acquisitions:			
Receivables, trade and other	$ 10.6	$ (14.5)	$ 25.1
Due from General Partner and affiliates	(55.6)	4.5	(60.1)
Accrued receivables	190.4	74.6	115.8
Inventory	56.2	26.9	29.3
Current and long-term other assets	(13.9)	(4.8)	(9.1)
Due to General Partner and affiliates	12.9	(11.0)	23.9
Accounts payable and other	(36.2)	(85.0)	48.8
Environmental liabilities	(7.7)	(42.0)	34.3
Accrued purchases	(121.3)	(6.3)	(115.0)
Interest payable	(0.8)	5.7	(6.5)
Property and other taxes payable	3.6	9.1	(5.5)
Net change in working capital accounts	$ 38.2	$ (42.8)	$ 81.0

The changes in our operating assets and liabilities, net of acquisitions as presented in our consolidated statements of cash flow for the three-month period ended March 31, 2015, compared to the same period in 2014, is primarily the result of items listed below coupled with general timing differences for cash receipts and payment associated with our third-party accounts. The main items affecting our cash flows from operating assets and liabilities include the following:

- The change in accrued receivables from December 31, 2014 to March 31, 2015, was primarily the result of collecting receivables at higher prices relative to current receivables recorded coupled with decreased sales of our receivables per our Receivables Agreement. For the three-month period ended March 31, 2014, our sales decreased due to a reduction in volumes offset by increased sales of receivables related to our Receivables Agreement;

- The decline in accrued purchases for the three-month period ended March 31, 2015 was primarily the result of lower prices of natural gas and NGLs combined with lower volumes purchased. Due to seasonal inventory buildup by the end of 2014, we had enough inventory to sustain the demand for natural gas during the cold weather season, thus we did not need to purchase as much gas to meet our commitments. For the three-month period ended March 31, 2014, payments and accruals were relatively flat;
- The change in accounts payable and other for the three-month period ended March 31, 2015 was primarily due to an accounts payable system implementation in December 2014 in which we paid our outstanding balances before the implementation. The primary driver of the decrease in accounts payable and other from December 31, 2013 to March 31, 2014 was primarily the result of a book overdraft that was present at December 31, 2013 that was not present at March 31, 2014 coupled with decreased operating accruals related to our liquid pipelines; and
- The decrease in environmental liabilities for the three-month period ended March 31, 2015 compared to the three-month period ended March 31, 2014 was primarily the result of less costs associated with the Line 6B crude oil release.

The above increase was partially offset by an increase in net income of $62.1 million offset by a $22.5 million increase in our non-cash items for the three-month period ended March 31, 2015 compared to the three-month period ended March 31, 2014. The increase in non-cash items primarily consisted of increased depreciation and amortization of $24.6 million due to phases of the Eastern Access and Mainline Expansion projects being placed in service in mid- to late 2014.

Investing Activities

Net cash used in our investing activities during the three-month period ended March 31, 2015 decreased by $63.8 million, compared to the same period of 2014, primarily due to increased asset acquisitions of 85.1 million due the acquisition of NGR's midstream assets. This increase was offset by decreased additions to property, plant and equipment, net of construction payables of $152.8 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.

Financing Activities

Net cash provided by our financing activities decreased $187.0 million for the three-month period ended March 31, 2015, compared to the same period in 2014, primarily due to the following:

- Increased repayments of $300.0 million to the General Partner for the A1 Loan during the three months ended March 31, 2015;
- Decreased net borrowings on the commercial paper program of $225.1 million in 2015, compared to 2014;
- Decreased capital contributions from noncontrolling interest of $90.2 million in 2015 for ownership interests in the Mainline Expansion Projects, Eastern Access Projects and Sandpiper Project; and
- Increased distributions to our limited partners of $15.8 million and distributions to noncontrolling interest of $90.7 million due to phases of the Eastern Access Project and Mainline Expansion Project being placed into service.

Offsetting the decreases above were the following:

- Increased net proceeds from our Class A unit issuance, including our General Partner's contributions of $294.8 million from 2015, while we had no issuances in 2014; and
- Increased borrowings under our credit facility of $240.0 million for 2015, compared to 2014.

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SUBSEQUENT EVENTS

Distribution to Partners

On April 30, 2015, the board of directors of Enbridge Management declared a distribution payable to our partners on May 15, 2015. The distribution will be paid to unitholders of record as of May 8, 2015 of our available cash of $249.9 million at March 31, 2015, or $0.5700 per limited partner unit. Of this distribution, $209.6 million will be paid in cash, $39.5 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.

Distribution to Series EA Interests

On April 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 $52.3 million to the noncontrolling interest in the Series EA, while $17.5 million will be paid to us.

Distribution to Series ME Interests

On April 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 $4.5 million to the noncontrolling interest in the Series ME, while $1.5 million will be paid to us.

Distribution from MEP

On April 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 May 15, 2015. The distribution will be paid to unitholders of record as of May 8, 2015, of MEP’s available cash of $16.0 million at March 31, 2015, or $0.3475 per limited partner unit. MEP will pay $7.4 million to their public Class A common unitholders, while $8.6 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 April 29, 2015, the general partner of Midcoast Operating declared a cash distribution by Midcoast Operating payable to its partners of record as of May 8, 2015. Midcoast Operating will pay $26.0 million to us and $27.8 million to MEP.

REGULATORY MATTERS

FERC Transportation Tariffs

Lakehead System

On February 27, 2015, we filed our annual rate adjustment 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.

North Dakota and Ozark System s

Effective April 1, 2015, we filed updates to the calculation of the surcharges on the two previously approved expansions, Phase 5 Looping and Phase 6 Mainline, on our North Dakota system. 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 volumes, and the Phase 6 Mainline surcharge decreased due to an increase in forecasted throughput as well as to return prior period over-recoveries to shippers.

Effective April 1, 2015, FERC tariff No. 3.8.0 cancelled transportation rates on the North Dakota System from Sherwood, North Dakota to Clearbrook, Minnesota as the pipeline is no longer providing service from that receipt point.

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 March 31, 2015.

Date of Maturity & Contract Type	Accounting Treatment	Notional	Average Fixed Rate [1]	Fair Value [2] at March 31, 2015	Fair Value [2] at 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%	$ (13.2)	$ (12.9)
Contracts maturing in 2018					
Interest Rate Swaps—Pay Fixed	Cash Flow Hedge	$ 810	2.24%	$ (5.3)	$ (1.3)
Contracts maturing in 2019					
Interest Rate Swaps—Pay Fixed	Cash Flow Hedge	$ 620	2.96%	$ (5.6)	$ (3.3)
Contracts settling prior to maturity					
2015—Pre-issuance Hedges	Cash Flow Hedge	$1,000	5.48%	$ (295.3)	$ (258.3)
2016—Pre-issuance Hedges	Cash Flow Hedge	$ 500	4.21%	$ (80.0)	$ (63.4)
2017—Pre-issuance Hedges	Cash Flow Hedge	$ 500	3.69%	$ (51.1)	$ (36.0)
2018—Pre-issuance Hedges	Cash Flow Hedge	$ 350	3.08%	$ (14.6)	$ (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 March 31, 2015 and December 31, 2014, respectively, discounted using the swap rate for the respective periods to consider the time value of money. Fair values exclude credit valuation adjustments of approximately $5.6 million of gains at March 31, 2015 and $37.4 million of gains at December 31, 2014, and cash collateral posted.

Fair Value Measurements of Commodity Derivatives

The following table provides summarized information about the fair values of expected cash flows of our outstanding commodity based swaps and physical contracts at March 31, 2015 and December 31, 2014.

	At March 31, 2015						At December 31, 2014	
			Wtd. Average Price (2)		Fair Value (3)		Fair Value (3)	
	Commodity	Notional (1)	Receive	Pay	Asset	Liability	Asset	Liability
Portion of contracts maturing in 2015								
Swaps								
Receive variable/pay fixed	Natural Gas	1,541,324	$ 2.61	$ 2.98	$ —	$ (0.6)	$ —	$ (0.7)
	NGL	504,250	$ 33.12	$40.52	$ 0.1	$ (3.8)	$ —	$ (6.8)
	Crude Oil	739,750	$ 52.35	$83.30	$ —	$ (22.9)	$ —	$ (27.4)
Receive fixed/pay variable	Natural Gas	1,728,938	$ 2.91	$ 2.71	$ 0.4	$ —	$ 3.7	$ —
	NGL	1,550,500	$ 46.19	$31.00	$24.0	$ (0.5)	$ 39.2	$ —
	Crude Oil	1,303,025	$ 93.91	$52.60	$53.8	$ —	$ 65.0	$ —
Receive variable/pay variable	Natural Gas	68,310,000	$ 2.56	$ 2.54	$ 2.6	$ (1.5)	$ 1.5	$ (1.7)
Physical Contracts								
Receive variable/pay fixed	Natural Gas	155,150	$ 2.39	$ 2.19	$ —	$ —	$ —	$ —
	NGL	80,000	$ 32.76	$41.89	$ —	$ (0.7)	$ —	$ (3.6)
	Crude Oil	11,000	$ 48.18	$51.64	$ —	$ —	$ —	$ —
Receive fixed/pay variable	Natural Gas	406,373	$ 2.46	$ 2.51	$ —	$ —	$ —	$ —
	NGL	398,525	$ 26.68	$21.93	$ 1.9	$ (0.1)	$ 19.8	$ —
	Crude Oil	109,000	$ 52.59	$50.02	$ 0.3	$ —	$ 0.5	$ —
Receive variable/pay variable	Natural Gas	192,448,455	$ 2.61	$ 2.61	$ 1.6	$ (0.5)	$ 2.2	$ (1.0)
	NGL	10,861,860	$ 18.50	$18.15	$ 3.9	$ (0.1)	$ 3.7	$ (1.0)
	Crude Oil	654,682	$ 46.53	$47.97	$ 1.0	$ (1.9)	$ 0.3	$ (1.7)
Portion of contracts maturing in 2016								
Swaps								
Receive variable/pay fixed	Natural Gas	363,514	$ 2.75	$ 3.41	$ —	$ (0.2)	$ —	$ (0.1)
	Crude Oil	415,950	$ 58.02	$82.69	$ —	$ (10.2)	$ —	$ (8.1)
Receive fixed/pay variable	Natural Gas	465,600	$ 3.32	$ 3.16	$ 0.1	$ —	$ —	$ —
	NGL	823,500	$ 39.64	$27.63	$ 9.8	$ —	$ 9.3	$ —
	Crude Oil	415,950	$ 85.08	$58.02	$11.2	$ —	$ 9.1	$ —
Receive variable/pay variable	Natural Gas	44,959,000	$ 2.93	$ 2.91	$ 2.0	$ (1.1)	$ 0.5	$ (0.3)
Physical Contracts								
Receive fixed/pay variable	Natural Gas	63,591	$ 3.12	$ 2.98	$ —	$ —	$ —	$ —
	NGL	4,398	$ 29.86	$25.91	$ —	$ —	$ —	$ —
Receive variable/pay variable	Natural Gas	59,944,569	$ 3.05	$ 3.04	$ 0.9	$ (0.4)	$ 0.7	$ (0.4)
	NGL	8,944,071	$ 18.00	$17.89	$ 0.9	$ —	$ —	$ —
Portion of contracts maturing in 2017								
Swaps								
Receive variable/pay fixed	Natural Gas	24,030	$ 3.24	$ 3.48	$ —	$ —	$ —	$ —
	NGL	547,500	$ 23.81	$25.86	$ —	$ (1.1)	$ —	$ —
	Crude Oil	547,500	$ 61.30	$66.72	$ —	$ (2.9)	$ —	$ —
Receive fixed/pay variable	NGL	547,500	$ 23.59	$23.81	$ 0.3	$ (0.5)	$ 0.7	$ —
	Crude Oil	547,500	$ 66.78	$61.30	$ 2.9	$ —	$ 0.8	$ —
Receive variable/pay variable	Natural Gas	2,700,000	$ 3.44	$ 3.37	$ 0.2	$ —	$ —	$ —
Physical Contracts								
Receive variable/pay variable	Natural Gas	28,047,550	$ 3.36	$ 3.35	$ 0.3	$ (0.1)	$ 0.2	$ (0.1)
Portion of contracts maturing in 2018								
Physical Contracts								
Receive variable/pay variable	Natural Gas	5,787,810	$ 3.57	$ 3.56	$ 0.1	$ —	$ —	$ —
Portion of contracts maturing in 2019								
Physical Contracts								
Receive variable/pay variable	Natural Gas	2,187,810	$ 3.56	$ 3.53	$ 0.1	$ —	$ —	$ —
Portion of contracts maturing in 2020								
Physical Contracts								
Receive variable/pay variable	Natural Gas	359,640	$ 3.88	$ 3.85	$ —	$ —	$ —	$ —

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

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

(3) The fair value is determined based on quoted market prices at March 31, 2015 and December 31, 2014, respectively, discounted using the swap rate for the respective periods to consider the time value of money. Fair values are presented in millions of dollars and exclude credit valuation adjustments of approximately $0.2 million of losses and $0.5 million of losses at March 31, 2015 and December 31, 2014, respectively, and cash collateral received.

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

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

(1) Volumes of natural gas are measured in MMBtu, whereas volumes of NGL and crude oil are measured in Bbl.
(2) Strike and market prices are in $/MMBtu for natural gas and in $/Bbl for NGL and crude oil.
(3) The fair value is determined based on quoted market prices at March 31, 2015 and December 31, 2014, respectively, discounted using the swap rate for the respective periods to consider the time value of money. Fair values are presented in millions of dollars and exclude credit valuation adjustments of approximately $0.6 million and $0.7 million of losses at March 31, 2015 and December 31, 2014, respectively, as well as cash collateral received.

Our credit exposure for 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.

	March 31, 2015	December 31, 2014
	(in millions)	
Counterparty Credit Quality (1)		
AAA	$ 0.4	$ 0.1
AA (2)	(94.0)	(49.8)
A	(225.9)	(129.1)
Lower than A (3)	6.6	17.9
	$ (312.9)	$ (160.9)

(1) As determined by nationally-recognized statistical ratings organizations.
(2) Includes $22.6 million and $28.4 million held of cash collateral at March 31, 2015 and December 31, 2014, respectively.
(3) Includes $0.7 million of cash collateral posted at March 31, 2015.

Item 4. Controls and Procedures

We and Enbridge maintain systems of disclosure controls and procedures designed to provide reasonable assurance that we are able to record, process, summarize and report the information required to be disclosed in the reports that we file or submit under the Securities Exchange Act of 1934, as amended, or the Exchange Act, within the time periods specified in the rules and forms of the Securities and Exchange Commission, and that such information is accumulated and communicated to our management, including our principal executive and principal financial officers, as appropriate, to allow timely decisions regarding required disclosure. Our management, with the participation of our principal executive and principal financial officers, has evaluated the effectiveness of our disclosure controls and procedures as of March 31, 2015. Based upon that evaluation, our principal executive and principal financial officers concluded that our disclosure controls and procedures are effective at the reasonable assurance level. In conducting this assessment, our management relied on similar evaluations conducted by employees of Enbridge affiliates who provide certain treasury, accounting and other services on our behalf.

There have been no changes in internal control over financial reporting that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting during the three-month period ended March 31, 2015.

PART II—OTHER INFORMATION

Item 1. Legal Proceedings

Refer to Part I, Item 1. *Financial Statements* , "Note 10. *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 6. Exhibits

Reference is made to the "Index of Exhibits" following the signature page, which we hereby incorporate into this Item.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

ENBRIDGE ENERGY PARTNERS, L.P.
(Registrant)

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

Date: May 1, 2015	By: /s/ Mark A. Maki Mark A. Maki *President and* *Principal Executive Officer*
Date: May 1, 2015	By: /s/ Stephen J. Neyland Stephen J. Neyland *Vice President—Finance* *(Principal Financial Officer)*

Index of Exhibits

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

Exhibit Number	Description
10.1	Credit Agreement (364-Day) dated as of March 9, 2015, by and among Enbridge Energy Partners, L.P. and Enbridge (U.S.) Inc. (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K, filed on March 9, 2015).
10.2	Commercial Paper Dealer Agreement dated as of March 20, 2015, between Enbridge Energy Partners, L.P., as Issuer, and Wells Fargo Securities, LLC, as Dealer (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K, filed on March 23, 2015).
31.1 *	Certification of Principal Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2 *	Certification of Principal Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1 *	Certification of Principal Executive Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2 *	Certification of Principal Financial Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
101.INS *	XBRL Instance Document.
101.SCH *	XBRL Taxonomy Extension Schema Document.
101.CAL *	XBRL Taxonomy Extension Calculation Linkbase Document.
101.DEF *	XBRL Taxonomy Extension Definition Linkbase Document.
101.LAB *	XBRL Taxonomy Extension Label Linkbase Document.
101.PRE *	XBRL Taxonomy Extension Presentation Linkbase Document.

Exhibit 31.1

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

I, Mark A. Maki, certify that:

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

Date: May 1, 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)

Exhibit 31.2

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

I, Stephen J. Neyland, certify that:

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

Date: May 1, 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)

Exhibit 32.1

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

The undersigned, being the Principal Executive Officer of Enbridge Energy Partners, L.P. (the "Partnership"), hereby certifies that the Partnership's Quarterly Report on Form 10-Q for the quarterly period ended March 31, 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: May 1, 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)

Exhibit 32.2

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

The undersigned, being the Principal Financial Officer of Enbridge Energy Partners, L.P. (the “Partnership”), hereby certifies that the Partnership’s Quarterly Report on Form 10-Q for the quarterly period ended March 31, 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: May 1, 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)