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 September 30, 2014

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
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 254,208,428 Class A common units outstanding as of November 3, 2014.

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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; and (7) changes in laws or regulations to which we are subject, including compliance with environmental and operational safety regulations that may increase costs of system integrity testing and maintenance.

For additional factors that may affect results, see "Item 1A. Risk Factors" included in our Annual Report on Form 10-K for the fiscal year ended December 31, 2013, 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 September 30,		For the nine month period ended September 30,	
	2014	2013	2014	2013
	(unaudited; in millions, except per unit amounts)			
Operating revenue (Note 10)	$1,874.0	$1,724.0	$5,663.6	$4,950.3
Operating revenue—affiliate (Note 8)	68.3	65.4	229.4	204.8
	1,942.3	1,789.4	5,893.0	5,155.1
Operating expenses:				
Cost of natural gas (Notes 4 and 10)	1,208.5	1,234.7	3,888.4	3,469.1
Cost of natural gas—affiliate (Note 8)	29.7	22.8	98.3	95.3
Environmental costs, net of recoveries (Note 9)	50.1	0.6	93.3	184.3
Operating and administrative	119.4	153.6	323.3	348.9
Operating and administrative—affiliate (Note 8)	115.9	111.5	353.6	329.1
Power (Note 10)	59.5	43.0	164.1	105.8
Depreciation and amortization	118.8	99.6	336.0	287.6
	1,701.9	1,665.8	5,257.0	4,820.1
Operating income	240.4	123.6	636.0	335.0
Interest expense, net (Notes 6 and 10)	137.1	70.5	294.2	226.4
Allowance for equity used during construction (Note 13)	14.5	9.3	47.8	25.2
Other income	1.8	0.4	2.2	1.0
Income before income tax expense	119.6	62.8	391.8	134.8
Income tax expense (Note 11)	2.1	1.5	6.1	17.5
Net income	117.5	61.3	385.7	117.3
Less: Net income attributable to:				
Noncontrolling interest (Note 8)	70.7	20.3	149.4	54.3
Series 1 preferred unit distributions	22.5	22.7	67.5	35.8
Accretion of discount on Series 1 preferred units	3.8	3.4	11.1	5.7
Net income attributable to general and limited partner ownership interests in Enbridge Energy Partners, L.P.	$ 20.5	$ 14.9	$ 157.7	$ 21.5
Net income (loss) allocable to limited partner interests	$ (14.5)	$ (17.6)	$ 49.5	$ (73.8)
Net income (loss) per limited partner unit (basic) (Note 2)	$ (0.04)	$ (0.05)	$ 0.15	$ (0.23)
Weighted average limited partner units outstanding (basic)	328.8	317.4	327.6	313.2
Net income (loss) per limited partner unit (diluted) (Note 2)	$ (0.04)	$ (0.05)	$ 0.15	$ (0.23)
Weighted average limited partner units outstanding (diluted)	328.8	317.4	327.6	313.2

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

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

	For the three month period ended September 30, 2014	For the three month period ended September 30, 2013	For the nine month period ended September 30, 2014	For the nine month period ended September 30, 2013
	(unaudited; in millions)			
Net income	$117.5	$ 61.3	$385.7	$117.3
Other comprehensive income (loss), net of tax expense (benefit) of $0.0 million $(0.1) million, $0.0 million and $0.0 million, respectively (Note 10)	55.5	(14.0)	(80.6)	177.7
Comprehensive income	173.0	47.3	305.1	295.0
Less: Comprehensive income attributable to:				
Noncontrolling interest (Note 8)	70.7	20.3	149.4	54.3
Series 1 preferred unit distributions	22.5	22.7	67.5	35.8
Accretion of discount on Series 1 preferred units	3.8	3.4	11.1	5.7
Other comprehensive income attributed to noncontrolling interest	2.1	—	1.8	—
Comprehensive income attributable to general and limited partner ownership interests in Enbridge Energy Partners, L.P.	$ 73.9	$ 0.9	$ 75.3	$199.2

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

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

	For the nine month period ended September 30, 2014	2013
	(unaudited; in millions)	
Cash provided by operating activities:		
Net income	$ 385.7	$ 117.3
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization (Note 5)	336.0	287.6
Derivative fair value net losses (Note 10)	62.7	16.8
Inventory market price adjustments (Note 4)	4.8	3.3
Environmental costs, net of recoveries (Note 9)	81.5	221.1
Distributions from investments in joint ventures (Note 8)	6.1	—
Equity earnings from investments in joint ventures (Note 8)	(7.1)	—
Deferred income taxes (Note 11)	1.5	13.5
State income taxes	3.2	7.9
Allowance for equity used during construction (Note 13)	(47.8)	(25.2)
Amortization of debt issuance and hedging costs	8.0	7.5
Other	5.0	3.2
Changes in operating assets and liabilities, net of acquisitions:		
Receivables, trade and other	0.9	66.2
Due from General Partner and affiliates	15.3	(4.9)
Accrued receivables	27.7	452.5
Inventory (Note 4)	(131.0)	(87.4)
Current and long-term other assets (Note 10)	(28.7)	(22.3)
Due to General Partner and affiliates	(23.4)	3.1
Accounts payable and other (Notes 3 and 10)	(93.1)	28.0
Environmental liabilities (Note 9)	(116.7)	(79.8)
Accrued purchases	(28.6)	(77.0)
Interest payable	5.9	8.3
Property and other taxes payable	23.8	8.1
Settlement of interest rate derivatives (Note 10)	—	(5.3)
Net cash provided by operating activities	491.7	942.5
Cash used in investing activities:		
Additions to property, plant and equipment (Notes 5 and 14)	(2,055.8)	(1,514.5)
Changes in restricted cash (Note 8)	31.2	(2.2)
Investments in joint ventures (Note 8)	(35.4)	(181.8)
Distributions from investments in joint ventures in excess of cumulative earnings	27.0	—
Other	(0.7)	(5.6)
Net cash used in investing activities	(2,033.7)	(1,704.1)
Cash provided by financing activities:		
Net proceeds from Series 1 preferred unit issuance	—	1,200.0
Net proceeds from unit issuances (Note 7)	—	519.3
Distributions to partners (Note 7)	(544.2)	(530.6)
Repayments to General Partner (Note 8)	(12.0)	(12.0)
Net proceeds from issuance of long-term debt (Note 6)	398.1	—
Repayments of long-term debt (Note 6)	—	(200.0)
Net borrowings under credit facility (Note 6)	30.0	—
Net commercial paper borrowings (repayments) (Note 6)	799.8	(734.9)
Contributions from noncontrolling interest (Notes 7 and 8)	1,083.0	355.2
Distributions to noncontrolling interest (Notes 7 and 8)	(80.9)	(39.7)
Net cash provided by financing activities	1,673.8	557.3
Net increase (decrease) in cash and cash equivalents	131.8	(204.3)
Cash and cash equivalents at beginning of year	164.8	227.9
Cash and cash equivalents at end of period	$ 296.6	$ 23.6

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

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

	September 30, 2014	December 31, 2013
	(unaudited; in millions)	
ASSETS		
Current assets:		
Cash and cash equivalents (Note 3)	$ 296.6	$ 164.8
Restricted cash (Note 8)	38.2	69.4
Receivables, trade and other, net of allowance for doubtful accounts of $0.5 million in 2014 and 2013 (Note 9)	48.5	49.4
Due from General Partner and affiliates	26.7	40.5
Accrued receivables	182.5	210.2
Inventory (Note 4)	221.1	94.9
Other current assets (Note 10)	74.5	47.6
	888.1	676.8
Property, plant and equipment, net (Note 5)	15,038.1	13,176.8
Goodwill	246.7	246.7
Intangibles, net	255.9	263.2
Other assets, net (Note 10)	518.3	538.0
	$ 16,947.1	$ 14,901.5
LIABILITIES AND PARTNERS' CAPITAL		
Current liabilities:		
Due to General Partner and affiliates (Note 8)	$ 98.0	$ 121.4
Accounts payable and other (Notes 3, 10 and 13)	632.3	822.0
Environmental liabilities (Note 9)	164.1	233.7
Accrued purchases	437.0	465.6
Interest payable	73.9	68.0
Property and other taxes payable (Note 11)	94.2	70.7
Note payable to General Partner (Note 8)	12.0	12.0
Current maturities of long-term debt (Note 6)	200.0	200.0
	1,711.5	1,993.4
Long-term debt (Note 6)	6,007.9	4,777.4
Loans from General Partner and affiliate (Note 8)	294.0	306.0
Due to General Partner and affiliates (Note 8)	125.8	58.2
Deferred income tax liability (Note 11)	19.0	17.4
Other long-term liabilities (Notes 9 and 10)	396.0	51.7
Total liabilities	8,554.2	7,204.1
Commitments and contingencies (Note 9)		
Partners' capital: (Notes 7 and 8)		
Series 1 preferred units (48,000,000 at September 30, 2014 and December 31, 2013)	1,171.8	1,160.7
Class D units (66,100,000 at September 30, 2014)	2,516.8	—
Class A common units (254,208,428 at September 30, 2014 and December 31, 2013)	240.1	2,979.0
Class B common units (7,825,500 at September 30, 2014 and December 31, 2013)	—	65.3
i-units (67,260,894 and 63,743,099 at September 30, 2014 and December 31, 2013, respectively)	675.9	1,291.9
Incentive distribution units (1,000 at September 30, 2014)	493.1	—
General Partner	199.9	301.5
Accumulated other comprehensive income (loss) (Note 10)	(159.0)	(76.6)
Total Enbridge Energy Partners, L.P. partners' capital	5,138.6	5,721.8
Noncontrolling interest (Note 8)	3,254.3	1,975.6
Total partners' capital	8,392.9	7,697.4
	$ 16,947.1	$ 14,901.5

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 of America, or GAAP, for interim consolidated financial information and with the instructions to Form 10-Q and Rule 10-01 of Regulation S-X. Accordingly, the unaudited interim consolidated financial statements do not include all the information and footnotes required by GAAP for complete consolidated financial statements. In the opinion of management, they contain all adjustments, consisting only of normal recurring adjustments, which management considers necessary to present fairly our financial position as of September 30, 2014, our results of operations for the three and nine month periods ended September 30, 2014, and 2013, and our cash flows for the nine month periods ended September 30, 2014, and 2013. We derived our consolidated statement of financial position as of December 31, 2013, from the audited financial statements included in our Annual Report on Form 10-K for the fiscal year ended December 31, 2013. Our results of operations for the nine month period ended September 30, 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, 2013.

Comparative Amounts

During the first quarter of 2014, we changed our reporting segments. The Marketing segment was combined with the Natural Gas segment to form one new segment named “Natural Gas.” There was no change to the Liquids segment.

This change was a result of our reorganization in connection with Midcoast Energy Partner, L.P.’s, or MEP’s, initial public offering, or IPO, of its Class A common units representing limited partnership interests. This reorganization prompted management to reassess the presentation of EEP’s reportable segments considering the financial information available and evaluated regularly by our Chief Operating Decision Maker. Our new segment reporting is consistent with how management makes resource allocation decisions, evaluates performance, and furthers the achievement of our long-term objectives. Financial information for the prior periods has been restated to reflect the change in reporting segments.

Additionally, we have reclassified certain prior period affiliate amounts related to operating revenue, the cost of natural gas, and operating and administrative expenses to conform to the current period presentation. These reclassifications did not impact net income.

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 partners 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 and limited partner interests 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

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agreement. Until July 1, 2014, we allocated the 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 %

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 IDUs.

The Class D units entitle the holder thereof to receive quarterly distributions equal to the amount derived by multiplying the number of Class D units outstanding by the distribution rate per unit paid on our Class A and Class B common units, collectively referred to as common units. The Class D units are convertible on a one-for-one basis into our Class A common units any time after the fifth anniversary of issuance, or July 1, 2019, at the holder's option. We may redeem the Class D units in whole or in part after the 30-year anniversary of issuance, or July 1, 2044, at our option for either a cash amount equal to the notional value per unit, or with newly issued Class A common units with an aggregate market value at redemption equal to 105% of the aggregate notional value of the Class D units being redeemed. The Class D units have a notional value of $31.35 per unit, which was the closing price of our Class A common units on June 17, 2014, and have the same voting rights as the Class A common units. In the event of a liquidation event (or any merger or other extraordinary transaction), the Class D units entitle the holder thereof to a preference in liquidation equal to 20% of the notional value, with such preference being increased by an additional 20% on each anniversary of issuance, resulting in a liquidation preference equal to 100% of the notional value on and after July 1, 2018.

The IDUs entitle the holder thereof to receive 23% of the incremental distributions we pay in excess of $0.5435 per common unit, i-unit, and Class D unit per quarter. In the event of any decrease in the Class A common unit distribution below the current quarterly distribution level of $0.5435 per unit in any quarter during the five years commencing with the fourth quarter of 2014, the distribution we pay on the Class D units will be adjusted to the amount that we would have paid in respect of the Previous IDRs had the Equity Restructuring not occurred. In addition, we reduced the third quarter 2014 distribution payable on the Class D units so that the aggregate distributions we pay in calendar year 2014 with respect to the Previous IDRs, the Class D units and the IDUs will not exceed the distribution that we would have paid in calendar year 2014 in respect to the Previous IDRs had the Equity Restructuring not occurred.

Beginning July 1, 2014, as established by our amended and restated 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 $0.5345	2 %	98 %
First Target Distribution	> $0.5345	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.

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We recorded the Class D units and IDUs at their fair values of $2,480.0 million and $491.7 million, respectively, with the offset 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 on a pro rata basis. We determined the fair values of the Class D units using a market approach based upon the closing price of the Class A common units as of July 1, 2014 adjusted for differences in specific rights granted to the Class D units and other economic factors that would affect the fair value of the Class D units. We determined the fair value of the IDUs using an income approach on the basis of discounted cash flows from expected quarterly distributions.

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

	For the three month period ended September 30,		For the nine month period ended September 30,	
	2014	2013	2014	2013
	(in millions, except per unit amounts)			
Net income	$ 117.5	$ 61.3	$ 385.7	$ 117.3
Less Net income attributable to:				
Noncontrolling interest	(70.7)	(20.3)	(149.4)	(54.3)
Series 1 preferred unit distributions	(22.5)	(22.7)	(67.5)	(35.8)
Accretion of discount on Series 1 preferred units	(3.8)	(3.4)	(11.1)	(5.7)
Net income attributable to general and limited partner interests in Enbridge Energy Partners, L.P.	20.5	14.9	157.7	21.5
Less distributions:				
Incentive distributions	(1.4)	(32.9)	(35.9)	(96.8)
Distributed earnings attributed to our General Partner	(4.5)	(3.6)	(12.6)	(10.6)
Distributed earnings attributed to Class D units	(33.1)	—	(69.8)	—
Total distributed earnings to our General Partner, Class D units, and IDUs	(39.0)	(36.5)	(118.3)	(107.4)
Total distributed earnings attributed to our common units and i-units	(182.8)	(176.5)	(542.7)	(518.6)
Total distributed earnings	(221.8)	(213.0)	(661.0)	(626.0)
Overdistributed earnings	$(201.3)	$(198.1)	$(503.3)	$(604.5)
Weighted average limited partner units outstanding	328.8	317.4	327.6	313.2
Basic and diluted earnings per unit:				
Distributed earnings per unit (1)	$ 0.56	$ 0.56	$ 1.66	$ 1.66
Overdistributed earnings per limited partner unit (2)	(0.60)	(0.61)	(1.51)	(1.89)
Net income (loss) per unit (basic and diluted) (3)	$ (0.04)	$ (0.05)	$ 0.15	$ (0.23)

(1) Represents the total distributed earnings to common units and i-units divided by the weighted average number of limited partner interests 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 September 30, 2014, 43,201,310 anti-dilutive Preferred units and 66,100,000 anti-dilutive Class D units were excluded from the if-converted method of calculating diluted earnings per unit. For the nine month period ended September 30, 2014, 43,201,310 anti-dilutive Preferred units and 22,275,458 anti-dilutive Class D units were excluded from the if-converted method of calculating diluted earnings per unit.

3. 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

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have made payments that have not yet been presented to the financial institution totaling approximately $16.2 million at September 30, 2014, and $24.0 million at December 31, 2013, are included in "Accounts payable and other" on our consolidated statements of financial position.

4. INVENTORY

Our inventory is comprised of the following:

	September 30, 2014	December 31, 2013
	(in millions)	
Materials and supplies	$ 2.2	$ 2.1
Crude oil inventory	12.3	18.0
Natural gas and NGL inventory	206.6	74.8
	$ 221.1	$ 94.9

The "Cost of natural gas and natural gas liquids" on our consolidated statements of income includes charges totaling $1.5 million and $0.9 million for the three month periods ended September 30, 2014 and 2013 respectively, and $4.8 million and $3.3 million for the nine month periods ended September 30, 2014 and 2013, respectively, that we recorded to reduce the cost basis of our inventory of natural gas and natural gas liquids, or NGLs, to reflect the current market value.

5. PROPERTY, PLANT AND EQUIPMENT

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

	September 30, 2014	December 31, 2013
	(in millions)	
Land	$ 43.1	$ 43.6
Rights-of-way	829.4	666.2
Pipelines	9,617.3	8,035.8
Pumping equipment, buildings and tanks	2,831.0	2,233.0
Compressors, meters and other operating equipment	2,124.1	1,989.8
Vehicles, office furniture and equipment	417.4	322.0
Processing and treating plants	514.2	514.4
Construction in progress	1,329.0	2,077.7
Total property, plant and equipment	17,705.5	15,882.5
Accumulated depreciation	(2,667.4)	(2,705.7)
Property, plant and equipment, net	$ 15,038.1	$ 13,176.8

During the nine month period ended September 30, 2014, we recorded asset retirement obligations, or AROs, of $100.6 million. Of that amount, $60.0 million is related to the pre-replacement Line 6B and $40.6 million is related to the pre-replacement Line 3. These AROs are recorded in "Accounts payable and other" and "Other long-term liabilities," respectively, with an offset to "Property, plant and equipment, net" in our consolidated statements of financial position. Both of these pipelines are part of our Lakehead system, and the AROs are related to the decommissioning of the original pipelines as we are completing Line 6B replacement work in 2014 and the Line 3 replacement with an estimated in-service date of late 2017. The associated ARO is a component of the pipelines category of "Property, plant and equipment, net." We record AROs at fair value in the period in which they can be reasonably determined. Fair value is determined based on expected future cash flows and estimated retirement periods, as well as discount and inflation rates.

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During the three month period ended September 30, 2014, we retired components of our pre-replacement Line 6B assets, including the related asset retirement costs, in the amount of $282.5 million. Consistent with the group method of depreciation, we charged the retirement of these components to accumulated depreciation.

6. DEBT

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

	September 30, 2014	December 31, 2013
	(in millions)	
EEP debt obligations:		
Commercial Paper	$ 1,100.0	$ 300.0
5.350% Senior Notes due 2014	200.0	200.0
5.875% Senior Notes due 2016	299.9	299.9
7.000% Senior Notes due 2018	99.9	99.9
6.500% Senior Notes due 2018	399.3	399.1
9.875% Senior Notes due 2019	500.0	500.0
5.200% Senior Notes due 2020	499.9	499.9
4.200% Senior Notes due 2021	599.2	599.1
7.125% Senior Notes due 2028	99.8	99.8
5.950% Senior Notes due 2033	199.8	199.8
6.300% Senior Notes due 2034	99.8	99.8
7.500% Senior Notes due 2038	399.1	399.0
5.500% Senior Notes due 2040	546.4	546.4
8.050% Junior subordinated notes due 2067	399.8	399.7
MEP debt obligations:		
MEP Credit Agreement	365.0	335.0
3.560% MEP Series A Senior Notes due 2019	75.0	—
4.040% MEP Series B Senior Notes due 2021	175.0	—
4.420% MEP Series C Senior Notes due 2024	150.0	—
Total	$ 6,207.9	$ 4,977.4

Interest Cost

Our interest cost for the three and nine month periods ended September 30, 2014, and 2013, is comprised of the following:

	For the three month period ended September 30, 2014	2013	For the nine month period ended September 30, 2014	2013
	(in millions)			
Interest expense	$ 137.1	$ 70.5	$ 294.2	$ 226.4
Interest capitalized	11.6	13.4	35.7	39.8
Interest cost incurred	$ 148.7	$ 83.9	$ 329.9	$ 266.2
Weighted average interest rate	*6.0%*	*6.3%*	*6.2%*	*6.1%*

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.

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On October 6, 2014, we amended our Credit Facility to extend the maturity date to September 26, 2019; however, $175.0 million of commitments will expire on the original maturity date of September 26, 2018.

On July 3, 2014, we amended our 364-Day Credit Facility to extend the revolving credit termination date to July 3, 2015, and to decrease aggregate commitments under the facility to $650.0 million. The 364-Day Credit Facility 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 September 30, 2014, which we use to fund our general activities and working capital needs.

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 September 30, 2014, we had approximately $1.1 billion in principal amount of commercial paper outstanding at a weighted average interest rate of 0.33%, excluding the effect of our interest rate hedging activities. Under our commercial paper program, we had net borrowings of approximately $799.8 million during the nine month period ended September 30, 2014, which includes gross borrowings of $7.4 billion and gross repayments of $6.6 billion. At December 31, 2013, we had $300.0 million in principal amount of commercial paper outstanding at a weighted average interest rate of 0.37%, 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 the ability and intent to refinance all of our commercial paper obligations on a long-term basis through borrowings under our Credit Facilities. Accordingly, such amounts have been classified as "Long-term debt" in our accompanying consolidated statements of financial position.

On February 3, 2014, we entered into 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. On September 9, 2014, we amended this uncommitted letter of credit arrangement to increase the aggregate amount 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 September 30, 2014, we have approximately $1.3 billion available under the terms of our Credit Facilities, determined as follows:

	(in millions)
Total credit available under Credit Facilities	$ 2,625.0
Less: Amounts outstanding under Credit Facilities	—
Principal amount of commercial paper outstanding	1,100.0
Letters of credit outstanding	183.6
Total amount available at September 30, 2014	$ 1,341.4

As of September 30, 2014, we were in compliance with the terms of all of our financial covenants under the Credit Facilities.

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MEP Credit Agreement

On November 13, 2013, MEP, Midcoast Operating L.P., or Midcoast Operating, and their material domestic subsidiaries, entered into a senior revolving credit facility, or 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 is 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. In connection with the amendment to the MEP Credit Agreement, we entered into an amended and restated subordination agreement by and among MEP, Midcoast Operating, the other parties from time to time party thereto and us in favor of Bank of America N.A., as administrative agent, and for the benefit of the administrative agent and the lenders party to the MEP Credit Agreement, to accommodate the subordination agreement entered into in connection with the MEP private debt issuance on September 30, 2014, described under "MEP Private Debt Issuance."

At September 30, 2014, MEP had $365.0 million in outstanding borrowings under the MEP Credit Agreement at a weighted average interest rate of 1.9%. Under the MEP Credit Agreement, we had net borrowings of approximately $30.0 million during the nine month period ended September 30, 2014, which includes gross borrowings of $5,570.0 billion and gross repayments of $5,540.0 billion. As of September 30, 2014, MEP was in compliance with the terms of its financial covenants.

MEP Private Debt Issuance

On September 30, 2014, MEP completed a private debt issuance of $400.0 million. The debt consists of three tranches of senior notes: $75.0 million of 3.56% Series A Senior Notes due in 2019; $175.0 million of 4.04% Series B Senior Notes due in 2021; and $150.0 million of 4.42% Series C Senior Notes due in 2024, collectively the Notes. All of the Notes pay interest semi-annually on March 31 and September 30, commencing on March 31, 2015. MEP received approximately $398.1 million in net proceeds, which were used to repay outstanding indebtedness and for other general partnership purposes. Using a portion of the net proceeds, MEP settled two interest rate swaps for a net payment of $0.9 million on September 30, 2014, which will be amortized to interest expense over the original 5 year hedge term.

The Notes were issued pursuant to a Note Purchase Agreement, or the Purchase Agreement, between MEP and the purchasers named therein. The Notes and all other obligations under the Purchase Agreement are unconditionally guaranteed by each of MEP's domestic material subsidiaries pursuant to a guaranty agreement. Until such time as MEP obtains an investment grade rating from either Moody's or S&P and upon certain trigger events, MEP and the guarantors will grant liens in their assets (subject to certain excluded assets) to secure the obligations under the Notes. There are currently no liens associated with the Notes.

Additionally, the Purchase Agreement contains various covenants and restrictive provisions which limit the ability of MEP and its subsidiaries to incur certain liens or permit such liens to exist, merge or consolidate with another company, dispose of assets, make distributions on or redeem or repurchase their equity interests, incur or guarantee additional debt, repay subordinated debt or certain debt owed to affiliates prior to maturity, alter MEP's lines of business, and enter into certain types of transactions with affiliates or subsidiaries that MEP is permitted to designate as unrestricted subsidiaries.

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

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In connection with MEP's entry into the Purchase Agreement, MEP, along with the guarantors and us, entered into a subordination agreement in which we agreed to subordinate our right to payment on obligations owed by Midcoast Operating under each of the Financial Support Agreement and the Working Capital Agreements, both entered into by and between Midcoast Operating and us on November 13, 2013, and liens, if secured, to the rights of the holders under the Purchase Agreement, subject to the terms and conditions of the subordination agreement in favor and for the benefit of the holders of the Notes.

Fair Value of Debt Obligations

The carrying amounts of our outstanding commercial paper, borrowings under our Credit Facilities, and MEP Credit Agreement approximate their fair values at September 30, 2014, and December 31, 2013, 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 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 $5.5 billion and $4.9 billion at September 30, 2014, and December 31, 2013, 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.

7. 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 nine month period ended September 30, 2014.

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)			
July 31, 2014	August 7, 2014	August 14, 2014	$ 0.5550	$ 224.7	$ 36.7	$ 0.8	$ 187.3
April 30, 2014	May 8, 2014	May 15, 2014	$ 0.5435	$ 214.5	$ 35.3	$ 0.7	$ 178.5
January 30, 2014	February 7, 2014	February 14, 2014	$ 0.5435	$ 213.7	$ 34.6	$ 0.7	$ 178.4

(1) We issued 3,517,795 i-units to Enbridge Management, the sole owner of our i-units, during 2014 in lieu of cash distributions.
(2) We retained an amount equal to 2% of the i-unit distribution from our General Partner to maintain its 2% general partner interest in us.

Changes in Partners' Capital

The following table presents significant changes in partners' capital accounts attributable to our General Partner and limited partners as well as the noncontrolling interests in our consolidated subsidiaries, Enbridge Energy, Limited Partnership, or OLP, and MEP, for the nine month periods ended September 30, 2014 and 2013. The noncontrolling interest in the OLP arises from the joint funding arrangements with our General Partner and its affiliate to finance: (1) construction of the U.S. portion of the Alberta Clipper crude oil pipeline and related facilities, which we refer to as the Alberta Clipper Pipeline; (2) 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 (3) further expansion of our Lakehead system to transport crude oil between Neche, North Dakota and Superior,

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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 nine month period ended September 30, 2014	2013
	(in millions)	
Series 1 Preferred interests		
Beginning balance	$1,160.7	$ —
Proceeds from issuance of preferred units	—	1,200.0
Net income	67.5	35.8
Accretion of discount on preferred units	11.1	5.7
Distribution payable	(67.5)	(35.8)
Beneficial conversion feature of preferred units	—	(47.7)
Ending balance	$1,171.8	$1,158.0
General and limited partner interests		
Beginning balance	$4,637.7	$4,774.9
Proceeds from issuance of partnership interests, net of costs	—	519.3
Net income	157.7	21.5
Distributions	(544.2)	(530.6)
Beneficial conversion feature of preferred units	—	47.7
Transfer of interests in subsidiary to Midcoast Energy Partners, L.P.	(125.4)	—
Ending balance	$4,125.8	$4,832.8
Accumulated other comprehensive loss		
Beginning balance	$ (76.6)	$ (320.5)
Changes in fair value of derivative financial instruments reclassified to earnings	22.2	21.3
Changes in fair value of derivative financial instruments recognized in other comprehensive income (loss)	(104.6)	156.4
Ending balance	$ (159.0)	$ (142.8)
Noncontrolling interest		
Beginning balance	$1,975.6	$ 793.5
Capital contributions	1,083.0	355.2
Transfer of interests in subsidiary to Midcoast Energy Partners, L.P.	125.4	—
Other comprehensive loss allocated to noncontrolling interest	1.8	—
Net income	149.4	54.3
Distributions to noncontrolling interest	(80.9)	(39.7)
Ending balance	$3,254.3	$1,163.3
Total partners' capital at end of period	$8,392.9	$7,011.3

Midcoast Energy Partners, L.P.

On November 13, 2013, MEP, one of our subsidiaries, completed its IPO of 18,500,000 Class A common units representing limited partner interests and subsequently issued an additional 2,775,000 Class A common units pursuant to the underwriter's exercise of their over allotment option. MEP received proceeds (net of underwriting discounts, structuring fees and offering expenses) of approximately $354.9 million. MEP used the net proceeds to distribute approximately $304.5 million to us, to pay approximately $3.4 million in revolving credit facility origination and commitment fees and used approximately $47.0 million to redeem 2,775,000 Class A common units from us. At September 30, 2014, we owned 5.9% of outstanding MEP Class A common units, 100% of the outstanding MEP Subordinated Units, 100% of MEP's general partner and 48.4% of the limited partner interests in Midcoast Operating.

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On July 1, 2014, we sold a 12.6% limited partner interest in Midcoast Operating to MEP, for $350.0 million in cash, which reduced our total ownership interest in Midcoast Operating from 61% to 48.4%. This transaction represents our first sale to MEP of additional interests in Midcoast Operating since MEP's IPO on November 13, 2013. We intend to sell additional interests in our natural gas assets, held through Midcoast Operating, to MEP and use the proceeds from any such sale as a source of funding for us. However, we do not know when, or if, any additional interests will be offered for sale.

The change in our total ownership interest in Midcoast Operating was recorded as an equity transaction, and no loss on the sale was recognized in our consolidated statements of income or comprehensive income. The increase in MEP's ownership interest in Midcoast Operating resulted in a reclassification of $125.4 million from the partners' capital accounts on a pro-rata basis to "Noncontrolling interest" in our consolidated statements of financial position.

8. 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 following table presents the affiliate amounts incurred by us for services received pursuant to the services agreements. The amounts we incurred are reflected in our consolidated statements of income by category.

	For the three month period ended September 30,		For the nine month period ended September 30,	
	2014	2013	2014	2013
	(in millions)			
Operating and administrative—affiliate	$ 115.9	$ 111.5	$ 353.6	$ 329.1

Distribution from MEP

The following table presents distributions paid by MEP to its public Class A common unitholders and us during the nine month period ended September 30, 2014, 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)	
July 31, 2014	August 14, 2014	$ 8.1	$ 6.9	$ 15.0
April 29, 2014	May 15, 2014	7.8	6.6	14.4
January 29, 2014	February 14, 2014	4.2	3.5	7.7
		$ 20.1	$ 17.0	$ 37.1

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Working Capital Credit Facility

On November 13, 2013, we entered into a $250.0 million Working Capital Loan Agreement, or the Working Capital Credit Facility, by and between Midcoast Operating, as borrower, and the Partnership, as lender. On October 30, 2014, we received a notice from Midcoast Operating that it is exercising its right under the Working Capital Agreement to terminate the Working Capital Agreement upon 30-days' notice, and such termination is expected to occur in the fourth quarter. As of September 30, 2014, there were no outstanding borrowings under the Working Capital Agreement.

Joint Funding Arrangement for Alberta Clipper Pipeline

In 2009, we entered into a joint funding arrangement with several of our affiliates and affiliates of Enbridge Inc., or Enbridge, to finance the construction of the United States segment of the Alberta Clipper Pipeline, which we refer to as the Series AC. As part of that arrangement, we have a credit agreement between our General Partner and us, which we refer to as the A1 Term Note. A summary of the cash activity for the A1 Term Note for the nine month periods ended September 30, 2014 and 2013 are as follows:

	A1 Term Note September 30,	
	2014	2013
	(in millions)	
Beginning Balance	$318.0	$330.0
Borrowings	—	—
Repayments	(12.0)	(12.0)
Ending Balance	$306.0	$318.0

We incurred interest expense under the A1 Term Note of $6.1 million and $18.3 million for the three and nine month periods ended September 30, 2014, respectively. We have presented the amounts in "Interest expense, net" on our consolidated statements of income.

We allocated earnings derived from operating the Alberta Clipper Pipeline in the amount of $16.3 million and $38.0 million for the three and nine month periods ended September 30, 2014, respectively, to our General Partner for its 66.67% share of the earnings of the Alberta Clipper Pipeline. We also allocated $13.4 million and $39.6 million of such earnings to our General Partner for the three and nine month periods ended September 30, 2013, respectively. We have presented the amounts we allocated to our General Partner for its share of the earnings of the Alberta Clipper Pipeline in "Net income attributable to noncontrolling interest" on our consolidated statements of income.

Distribution to Series AC Interests

The following table presents distributions paid by the OLP to our General Partner and its affiliate during the nine month period ended September 30, 2014, 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.

Distribution Declaration Date	Distribution Payment Date	Amount Paid to Partnership	Amount paid to the noncontrolling interest	Total Series AC Distribution
			(in millions)	
July 31, 2014	August 14, 2014	$ 7.4	$ 14.8	$ 22.2
April 30, 2014	May 15, 2014	6.6	13.1	19.7
January 30, 2014	February 14, 2014	6.4	12.8	19.2
		$ 20.4	$ 40.7	$ 61.1

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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 $550.5 million and $272.5 million to the OLP during the nine month periods ended September 30, 2014 and 2013, respectively, to fund its equity portion of the construction costs associated with the Eastern Access Projects.

We allocated earnings from the Eastern Access Projects in the amount of $41.7 million and $90.5 million to our General Partner for its ownership of the EA interest for the three and nine month periods ended September 30, 2014, respectively. We allocated earnings derived from the Eastern Access Projects in the amount of $6.6 million and $14.4 million to our General Partner for the three and nine month periods ended September 30, 2013, respectively. We have presented the amount allocated to our General Partner in “Net income attributable to noncontrolling interest” on our consolidated statements of income.

Distribution to Series EA Interests

The following table presents distributions paid by the OLP to our General Partner and its affiliate during the nine month period ended September 30, 2014, 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)	
July 31, 2014	August 14, 2014	$ 5.6	$ 16.7	$ 22.3
April 29, 2014	May 15, 2014	2.5	6.5	9.0
		$ 8.1	$ 23.2	$ 31.3

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 parallels the Eastern Access Joint Funding Agreement.

Our General Partner has made equity contributions totaling $384.0 million and $82.7 million to the OLP for the nine month periods ended September 30, 2014, and 2013, respectively, to fund its equity portion of the construction costs associated with the Mainline Expansion Projects.

We allocated earnings from the Mainline Expansion Projects in the amount of $9.8 million and $20.0 million to our General Partner for its ownership of the ME interest for the three and nine month periods ended September 30, 2014, respectively. We allocated earnings derived from the Mainline Expansion Projects in the amount of $0.3 million to our General Partner for the three and nine month periods ended September 30, 2013, respectively. We have presented the amount we allocated to our General Partner in “Net income attributable to noncontrolling interest” on our consolidated statements of income.

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Sale of Accounts Receivable

For the three and nine month periods ended September 30, 2014, we sold and derecognized $1,260.1 million and $3,792.8 million, respectively, of receivables to a wholly owned subsidiary of Enbridge. For the three and nine month periods ended September 30, 2014, the cash proceeds were $1,259.8 million and $3,791.8 million, respectively, which was remitted to us through our centralized treasury system. As of September 30, 2014, $411.1 million of the receivables were outstanding and had not been collected on behalf of the Enbridge subsidiary.

Consideration for the receivables sold is equivalent to the carrying value of the receivables less a discount for credit risk. The difference between the carrying value of the receivables sold and the cash proceeds received is recognized in "Operating and administrative-affiliate" expense in our consolidated statements of income. For the three and nine month periods ended September 30, 2014, the cost stemming from the discount on the receivables sold was not material.

As of September 30, 2014 and December 31, 2013, we had $38.2 million and $69.4 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 September 30, 2014.

Affiliate Revenues and Purchases

We record operating revenues in our Liquids segment for storage, transportation and terminaling services we provide to affiliates. The sales to affiliates are presented in "Operating revenue—affiliate" on our consolidated statements of income. Purchases of natural gas, natural gas liquids, or NGLs, and crude oil from Enbridge and its affiliates are presented in "Cost of natural gas—affiliate" on our consolidated statements of income.

The following table presents our results for the three and nine month periods ended September 30, 2014, and September 30, 2013, for operating revenues from sales to Enbridge and its affiliates and costs of natural gas, NGLs and crude oil purchases from Enbridge and its affiliates.

	For the three month period ended September 30,		For the nine month period ended September 30,	
	2014	2013	2014	2013
	(in millions)			
Operating revenue—affiliate	$ 68.3	$ 65.4	$ 229.4	$ 204.8
Cost of natural gas—affiliate	$ 29.7	$ 22.8	$ 98.3	$ 95.3

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 580-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 September 30, 2014 and December 31, 2013, was $380.2 million and $371.3 million, respectively, which is included on our consolidated statements of financial position in "Other assets, net." For the three and nine month periods ending September 30, 2014, we recognized $6.1 million and $7.1 million of equity earnings, respectively, in "Other income (expense)" on our consolidated statements of income related to our investment in the system.

For the three and nine month periods ended September 30, 2014, we incurred $5.4 million and $16.8 million, respectively, of pipeline transportation and demand fees from Texas Express NGL system for our Natural Gas business. We did not incur any fees from the Texas Express NGL system for the three and nine month periods ended September 30, 2013. These expenses are included in "Cost of natural gas – affiliate" on our consolidated statements of income.

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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 2014 to 2023.

9. 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 environmental liabilities through 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 September 30, 2014 and December 31, 2013, we had $64.0 million and $25.8 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 Pipeline and Hazardous Materials Safety Administration, or 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. In connection with this crude oil release, the cost estimate is approximately $7.0 million, excluding possible fines and penalties. As of September 30, 2014, we made payments of $6.0 million, and we have a remaining estimated liability of $1.0 million.

Lakehead Line 6B Crude Oil Release

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 Environmental Protection Agency, or EPA, which we refer to as the Order, that defined the scope which requires additional containment and active recovery of submerged oil relating to the Line 6B crude oil release. We submitted our initial proposed work plan required by the EPA on April 4, 2013, and we resubmitted the workplan on April 23, 2013, and again on May 1, 2013, based on EPA comments. The EPA approved the Submerged Oil Recovery and Assessment workplan, or SORA, with modifications on May 8, 2013. We incorporated the modification and submitted an approved SORA on May 13, 2013. At this time we have completed substantially all of the SORA.

We are also working with the Michigan Department of Environmental Quality, or MDEQ, to transition submerged oil reassessment, sheen management and sediment trap monitoring and maintenance activities from the EPA to the MDEQ, through a Kalamazoo River Residual Oil Monitoring and Maintenance Work Plan or, the Plan.

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As of September 30, 2014, our total cost estimate for the Line 6B crude oil release is $1.21 billion, which is an increase of $85.9 million as compared to December 31, 2013. On May 28, 2014 the MDEQ, Water Resource Division, approved our Schedule of Work for the remainder of 2014. Of the total cost increase of $50.9 million during the three month period ended September 30, 2014, $33.0 million is primarily related to the MDEQ approved Schedule of Work, and completion of the dredge activities near Ceresco and Morrow Lake, and $17.9 million is related to an increase of estimated civil penalties under the Clean Water Act of the United States, as described below under *Lines 6A & 6B Fines and Penalties*.

For purposes of estimating our expected losses associated with the Line 6B crude oil release, we have included those costs that we considered probable and that could be reasonably estimated at September 30, 2014. 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 6A & 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 & Equipment	$ 551.6
Environmental Consultants	227.0
Professional, regulatory and other	429.4
Total	$ 1,208.0

For the nine month periods ended September 30, 2014 and 2013, we made payments of $117.4 million and $62.3 million, respectively, for costs associated with the Line 6B crude oil release. As of September 30, 2014 and December 31, 2013, we had a remaining estimated liability of $219.4 million and $258.9 million, respectively.

Lines 6A & 6B Fines and Penalties

On September 9, 2010, a crude oil release occurred on Line 6A in Romeoville, Illinois. Due to the absence of sufficient information, we cannot provide a reasonable estimate of the liability for potential fines and penalties that could be assessed in connection with the Line 6A release. At September 30, 2014, our total estimated costs for the Line 6A crude oil release do not include an estimate for fines and penalties, which may be imposed by the EPA and PHMSA, in addition to other federal, state and local governmental agencies.

At September 30, 2014, our estimated costs related to the Line 6B crude oil release included $47.5 million in fines and penalties. Of this amount, $3.7 million related to civil penalties assessed by PHMSA that we paid during the third quarter of 2012. The total also included an amount of $40.0 million related 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

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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 measures directed toward enhancing spill prevention, leak detection, and emergency response to environmental events, and the cost of compliance with such measures could be significant. 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. Including our remediation spending through September 30, 2014, we have exceeded the limits of coverage under this insurance policy. As of September 30, 2014, 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 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.

Of the remaining $103.0 million coverage limit, $85.0 million is the subject matter of the lawsuit Enbridge filed in March 2013 against one particular insurer who is disputing our recovery eligibility for costs related to our claim on the Line 6B oil release. The recovery of the remaining $18.0 million is awaiting resolution of this lawsuit. While we believe those costs are eligible for recovery, there can be no assurance that we will prevail in our lawsuit.

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

Enbridge renewed its comprehensive property and liability insurance programs under which we are insured through April 30, 2015, having a liability aggregate limit of $700.0 million, including sudden and accidental pollution liability. The deductible applicable to oil pollution events was increased to $30.0 million per event, from the previous $10.0 million. 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.

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A number of governmental agencies and regulators have initiated investigations into the Line 6B crude oil release. Approximately 10 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.

Governmental agencies and regulators have also initiated investigations into the Line 6A crude oil release. One claim was filed against us and our affiliates by the State of Illinois in an Illinois state court in connection with this crude oil release, and the parties are currently operating under an agreed interim order. The costs associated with this order are included in the estimated environmental costs accrued for the Line 6A crude oil release. We are also 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.

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.

10. 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, power 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. We have hedged a portion of our exposure to variability in future cash flows associated with the risks discussed above through 2019 in accordance with our risk management policies.

Accounting Treatment

Effective January 1, 2014, we elected to prospectively change the presentation of derivative assets and liabilities from a net basis to a gross basis in the Consolidated Statements of Financial Position. We adopted this change to provide more detailed information about the future economic benefits and obligations associated with our derivative activities in our Consolidated Statements of Financial Position. This change had no impact to the Consolidated Statements of Income, Net income (loss) per limited partner unit, or Partners' capital.

Non-Qualified Hedges

Many of our derivative financial instruments qualify for hedge accounting treatment as set forth in the authoritative accounting guidance. However, we have transaction types associated with our commodity derivative financial instruments where the hedge structure does not meet the requirements to apply hedge accounting. As a result, these derivative financial instruments do not qualify for hedge accounting and are referred to as non-qualifying. These non-qualifying derivative financial instruments are marked-to-market each period with the change in fair value, representing unrealized gains and losses, included in "Cost of natural gas," "Operating revenue", "Power" or "Interest expense" in our consolidated statements of income. These mark-to-market adjustments produce a degree of earnings volatility that can often be significant from period to period, but have no cash flow impact relative to changes in market prices. The cash flow impact occurs when the underlying physical transaction takes place in the future and the associated financial instrument contract settlement is made.

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The following transaction types do not qualify for hedge accounting and contribute to the volatility of our income and cash flows:

Commodity Price Exposures:

- **Transportation**—In our Natural Gas segment, when we transport natural gas from one location to another, the pricing index used for natural gas sales is usually different from the pricing index used for natural gas purchases, which exposes us to market price risk relative to changes in those two indices. By entering into a basis swap, where we exchange one pricing index for another, we can effectively lock in the margin, representing the difference between the sales price and the purchase price, on the combined natural gas purchase and natural gas sale, removing any market price risk on the physical transactions. Although this represents a sound economic hedging strategy, the derivative financial instruments (i.e., the basis swaps) we use to manage the commodity price risk associated with these transportation contracts do not qualify for hedge accounting, since only the future margin has been fixed and not the future cash flow. As a result, the changes in fair value of these derivative financial instruments are recorded in earnings.
- **Storage**—In our Natural Gas segment, we use derivative financial instruments (i.e., natural gas, crude oil and NGL swaps) to hedge the relative difference between the injection price paid to purchase and store natural gas, crude oil and NGLs and the withdrawal price at which these commodities are sold from storage. The intent of these derivative financial instruments is to lock in the margin, representing the difference between the price paid for the natural gas, crude oil and NGLs injected and the price received upon withdrawal of these commodities from storage in a future period. We do not pursue cash flow hedge accounting treatment for these storage transactions since the underlying forecasted injection or withdrawal of these commodities, may not occur in the period as originally forecast. This can occur because we have the flexibility to make changes in the underlying injection or withdrawal schedule, based on changes in market conditions. In addition, since the physical commodities are recorded at the lower of cost or market, timing differences can result when the derivative financial instrument is settled in a period that is different from the period the physical commodity is sold from storage. As a result, derivative financial instruments associated with our storage activities can create volatility in our earnings.
- **Condensate, Natural Gas and NGL Options**—In our Natural Gas segment, we use options to hedge the forecasted commodity exposure of our condensate, NGLs and natural gas. Although options can qualify for hedge accounting treatment, pursuant to the authoritative accounting guidance, we have elected non-qualifying treatment. As such, our option premiums are expensed as incurred. These derivatives are being marked-to-market, with the changes in fair value recorded to earnings each period. As a result, our operating income is subject to volatility due to movements in the prices of condensate, NGLs and natural gas until the underlying long-term transactions are settled.
- **Optional Natural Gas Processing Volumes**—In our Natural Gas segment, we use derivative financial instruments to hedge the volumes of NGLs produced from our natural gas processing facilities. Some of our natural gas contracts allow us the choice of processing natural gas when it is economical and to cease doing so when processing becomes uneconomic. We have entered into derivative financial instruments to fix the sales price of a portion of the NGLs that we produce at our discretion and to fix the associated purchase price of natural gas required for processing. We typically designate derivative financial instruments associated with NGLs we produce per contractual processing requirements as cash flow hedges when the processing of natural gas is probable of occurrence. However, we are precluded from designating the derivative financial instruments as qualifying hedges of the respective commodity price risk when the discretionary processing volumes are subject to change. As a result, our operating income is subject to increased volatility due to fluctuations in NGL prices until the underlying transactions are settled or offset.
- **NGL and Crude Oil Forward Contracts**—In our Natural Gas segment, we use forward contracts to fix the price of NGLs and crude oil we purchase and to fix the price of NGLs and crude oil that we sell

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to meet the demands of our customers that sell and purchase NGLs and crude oil. A subgroup of physical NGL and physical crude oil contracts qualify for the normal purchases and normal sales, or NPNS scope exception. All other forward contracts are being marked-to-market each period with the change in fair value recorded in earnings. As a result, our operating income is subject to additional volatility associated with fluctuations in NGL and crude oil prices until the forward contracts are settled.

- **Natural Gas Forward Contracts**—In our Natural Gas segment, we use forward contracts to sell natural gas to our customers. A subgroup of physical natural gas contracts qualify for the NPNS scope exception. All other forward contracts are being marked-to-market each period with the change in fair value recorded in earnings. As a result, our operating income is subject to additional volatility associated with the changes in fair value of these contracts.
- **Crude Oil Contracts**—In our Liquids segment, we use forward contracts to hedge a portion of the crude oil length inherent in the operation of our pipelines, which we subsequently sell at market rates. These hedges create a fixed sales price for the crude oil that we will receive in the future. We elected not to designate these derivative financial instruments as cash flow hedges, and as a result, will experience some additional volatility associated with fluctuations in crude oil prices until the underlying transactions are settled or offset.
- **Power Purchase Agreements**—In our Liquids segment, we use forward physical power agreements to fix the price of a portion of the power consumed by our pumping stations in the transportation of crude oil in our owned pipelines. We designate these derivative agreements as non-qualifying hedges because they fail to meet the criteria for cash flow hedging or the NPNS exception. As various states in which our pipelines operate have legislated either partially or fully deregulated power markets, we have the opportunity to create economic hedges on power exposure. As a result, our operating income is subject to additional volatility associated with changes in the fair value of these agreements due to fluctuations in forward power prices.

Except for physical power, in all instances related to the commodity exposures described above, the underlying physical purchase, storage and sale of the commodity is accounted for on a historical cost or net realizable value basis rather than on the mark-to-market basis we employ for the derivative financial instruments used to mitigate the commodity price risk associated with our storage and transportation assets. This difference in accounting (i.e., the derivative financial instruments are recorded at fair market value while the physical transactions are recorded at the lower of historical or net realizable value) can and has resulted in volatility in our reported net income, even though the economic margin is essentially unchanged from the date the transactions were consummated. Relating to the power purchase agreements, commodity power purchases are immediately consumed as part of pipeline operations and are subsequently recorded as actual power expenses each period.

Derivative Positions

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

	September 30, 2014	December 31, 2013
	(in millions)	
Other current assets	$ 37.8	$ 21.2
Other assets, net	36.2	74.4
Accounts payable and other [1]	(25.6)	(172.0)
Other long-term liabilities	(267.9)	(12.3)
Due from general partner and affiliates	0.4	—
	$ (219.1)	$ (88.7)

(1) Includes $16.7 million of cash collateral at December 31, 2013.

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

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

	September 30, 2014	December 31, 2013
	(in millions)	
Counterparty Credit Quality (1)		
AAA	$ 0.3	$ 0.3
AA	(91.0)	(49.7)
A (2)	(134.0)	(40.1)
Lower than A	5.6	0.8
	$ (219.1)	$ (88.7)

(1) As determined by nationally-recognized statistical ratings organizations.
(2) Includes $16.7 million of cash collateral at December 31, 2013.

As the net value of our derivative financial instruments has decreased in response to changes in forward commodity prices, our outstanding financial exposure to third parties has also decreased. When credit thresholds are met pursuant to the terms of our International Swaps and Derivatives Association, Inc., or ISDA®, financial contracts, we have the right to require collateral from our counterparties. We include any cash collateral received in the balances listed above. When we are in a position of posting collateral to cover our counterparties' exposure to our non-performance, the collateral is provided through letters of credit, which are not reflected above.

At September 30, 2014, we had no cash collateral on our asset exposures, and at December 31, 2013, we held $16.7 million of cash collateral on our asset exposures, and we have provided letters of credit totaling $183.0 million and $76.1 million relating to our liability exposures pursuant to the margin thresholds in effect, respectively, under our ISDA® agreements.

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 September 30, 2014, we would have been required to provide additional letters of credit in the amount of $48.8 million.

At September 30, 2014 and December 31, 2013, we had credit concentrations in the following industry sectors, as presented below:

	September 30, 2014	December 31, 2013
	(in millions)	
United States financial institutions and investment banking entities	$ (176.3)	$ (85.0)
Non-United States financial institutions (1)	(49.3)	0.8
Other	6.5	(4.5)
	$ (219.1)	$ (88.7)

(1) Includes $16.7 million of cash collateral at December 31, 2013.

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

Effect of Derivative Instruments on the Consolidated Statements of Financial Position

		Asset Derivatives		Liability Derivatives	
		Fair Value at		Fair Value at	
	Financial Position Location	September 30, 2014	December 31, 2013	September 30, 2014	December 31, 2013
		(in millions)			
Derivatives designated as hedging instruments [1]					
Interest rate contracts	Other current assets	$ —	$ 8.1	$ —	$ —
Interest rate contracts	Other assets	16.9	57.1	—	—
Interest rate contracts	Accounts payable and other [2]	—	11.9	(7.8)	(145.5)
Interest rate contracts	Other long-term liabilities	—	—	(255.0)	(11.3)
Commodity contracts	Other current assets	3.3	2.0	—	(0.6)
Commodity contracts	Other assets	1.3	3.5	—	(0.5)
Commodity contracts	Accounts payable and other	—	1.9	(2.2)	(12.7)
Commodity contracts	Other long-term liabilities	—	0.6	(0.3)	(1.4)
		21.5	85.1	(265.3)	(172.0)
Derivatives not designated as hedging instruments					
Commodity contracts	Other current assets	34.5	11.8	—	(0.1)
Commodity contracts	Other assets	18.0	17.6	—	(3.3)
Commodity contracts	Accounts payable and other	—	5.4	(15.6)	(16.3)
Commodity contracts	Other long-term liabilities	—	—	(12.6)	(0.2)
Commodity contracts	Due from general partner and affiliates	0.4	—	—	—
		52.9	34.8	(28.2)	(19.9)
Total derivative instruments		$ 74.4	$ 119.9	$ (293.5)	$ (191.9)

(1) Includes items currently designated as hedging instruments. Excludes the portion of de-designated hedges which may have a component remaining in AOCI.
(2) Liability derivatives exclude $16.7 million of cash collateral at December 31, 2013.

Accumulated Other Comprehensive Income

We record the change in fair value of our derivative financial instruments that qualify for and are designated as a cash flow hedge, which is a hedge of a forecasted transaction or future cash flows, in "Accumulated other comprehensive income", also referred to as AOCI, a component of "Partners' capital," until the underlying hedged transaction occurs. Upon settlement of the designated cash flow hedges, gains (losses) are reclassified to earnings. Also included in AOCI, as of September 30, 2014, are unrecognized losses of approximately $29.6 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 nine month period ended September 30, 2014, unrealized commodity hedge losses of

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$0.2 million were de-designated as a result of the hedges no longer meeting hedge accounting criteria. We estimate that approximately $11.7 million, representing unrealized net losses from our cash flow hedging activities based on pricing and positions at September 30, 2014, will be reclassified from AOCI to earnings during the next 12 months.

During the first quarter of 2014 it was 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 meet the cash flow hedging requirements. These terminations resulted in realized losses of $0.8 million for the nine month period ended September 30, 2014.

Our earnings and cash flows are exposed to the variability in longer term interest rates ahead of the anticipated fixed rate debt issuances. Forward starting interest rate swaps are used as cash flow hedges against the effect of future interest rate movements on earnings and cash flow. In order to mitigate the negative effect that increasing interest rates can have on our cash flows, we have purchased 10 year interest rate swaps with a total notional value of $ 2.35 billion as of September 30, 2014.

In September 2014, we amended the maturity date on certain interest rate hedges of future debt issuances that were originally set to mature in 2014 and 2016 to better reflect the expected timing of future debt issuances. The ineffective portion of the hedges fair value in relation to the hedged future debt issuances is recognized in income at the amendment date and each quarter end. For the three and nine months ended September 30, 2014, interest expense increased due to recognition of unrealized losses for hedge ineffectiveness of approximately $62.2 million associated with interest rate hedges that were originally set to mature in 2014 and 2016.

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 September 30, 2014					
Interest rate contracts	$ 44.1	Interest expense	$ (4.0)	Interest expense	$ (62.2)
Commodity contracts	11.2	Cost of natural gas	(2.1)	Cost of natural gas	0.9
Total	$ 55.3		$ (6.1)		$ (61.3)
For the three month period ended September 30, 2013					
Interest rate contracts	$ 1.7	Interest expense	$ (4.2)	Interest expense	$ (1.1)
Commodity contracts	(17.2)	Cost of natural gas	(0.6)	Cost of natural gas	(0.5)
Total	$ (15.5)		$ (4.8)		$ (1.6)
For the nine month period ended September 30, 2014					
Interest rate contracts	$ (93.0)	Interest expense	$ (12.1)	Interest expense	$ (73.2)
Commodity contracts	7.9	Cost of natural gas	(12.4)	Cost of natural gas	1.5
Total	$ (85.1)		$ (24.5)		$ (71.7)
For the nine month period ended September 30, 2013					
Interest rate contracts	$ 179.3	Interest expense	$ (24.3)	Interest expense	$ (0.5)
Commodity contracts	(8.8)	Cost of natural gas	3.0	Cost of natural gas	1.8
Total	$ 170.5		$ (21.3)		$ 1.3

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

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Components of Accumulated Other Comprehensive Income/(Loss)

	Cash Flow Hedges (in millions)
Balance at December 31, 2013	$ (76.6)
Other Comprehensive Income before reclassifications (1)	(104.6)
Amounts reclassified from AOCI (2) (3)	22.2
Tax benefit (expense)	—
Net other comprehensive income	$ (82.4)
Balance at September 30, 2014	$ (159.0)

(1) Excludes NCI loss of $0.5 million reclassified from AOCI at September 30, 2014.
(2) Excludes NCI gain of $2.3 million reclassified from AOCI at September 30, 2014.
(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 September 30,		For the nine month period ended September 30,	
	2014	2013	2014	2013
	(in millions)			
Losses (gains) on cash flow hedges:				
Interest Rate Contracts (1)	$ 4.0	$ 4.2	$ 12.1	$ 24.3
Commodity Contracts (2) (3)	1.6	0.6	10.1	(3.0)
Total Reclassifications from AOCI	$ 5.6	$ 4.8	$ 22.2	$ 21.3

(1) Loss reported within "Interest expense" in the consolidated statements of income.
(2) Loss (gain) reported within "Cost of natural gas" in the consolidated statements of income.
(3) Excludes NCI gain of $0.5 million and $2.3 million reclassified from AOCI for the three and nine month periods ending September 30, 2014.

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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 September 30, 2014	For the three month period ended September 30, 2013 (2)	For the nine month period ended September 30, 2014	For the nine month period ended September 30, 2013 (2)
		Amount of Gain or (Loss) Recognized in Earnings (3)		Amount of Gain or (Loss) Recognized in Earnings (3)	
		(in millions)			
Interest rate contracts	Interest expense (4)	$ —	$ 0.1	$ —	$ —
Commodity contracts	Operating revenue (5)	14.6	(16.7)	10.1	(14.0)
Commodity contracts	Operating revenue—Affiliate	—	—	0.5	—
Commodity contracts	Power	—	0.1	0.5	0.3
Commodity contracts	Cost of natural gas (6)	9.5	(21.8)	(9.9)	(2.6)
Total		$ 24.1	$ (38.3)	$ 1.2	$ (16.3)

(1) Does not include settlements associated with derivative instruments that settle through physical delivery.
(2) The effects of derivative instruments on consolidated statements of income for the three and nine month periods ended September 30, 2013 have been revised to include settlement gains (losses) on derivatives not designated as hedge instruments of $(0.8) million and $1.8 million, respectively. The revisions to the disclosure had no impact on previously reported net income or earnings per unit.
(3) 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.
(4) Includes settlement gains of $0.1 million and $0.3 million for the three and nine month periods ended September 30, 2013, respectively.
(5) Includes settlement gains (losses) of $0.6 million and $(0.7) million for the three month periods ended September 30, 2014 and September 30, 2013, respectively, and $0.9 million and $1.0 million for the nine month periods ended September 30, 2014 and September 30, 2013, respectively.
(6) Includes settlement gains (losses) of $0.2 million and $(0.2) million for the three month periods ended September 30, 2014 and September 30, 2013, respectively, and $(8.6) million and $0.5 million for the nine month periods ended September 30, 2014 and September 30, 2013, 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 September 30, 2014				
	Gross Amount of Recognized Assets	Gross Amount Offset in the Statement of Financial Position	Net Amount of Assets Presented in the Statement of Financial Position	Gross Amount Not Offset in the Statement of Financial Position	Net Amount
			(in millions)		
Description:					
Derivatives	$ 74.4	$ —	$ 74.4	$ (33.6)	$ 40.8
Total	$ 74.4	$ —	$ 74.4	$ (33.6)	$ 40.8

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	As of December 31, 2013				
	Gross Amount of Recognized Assets	Gross Amount Offset in the Statement of Financial Position	Net Amount of Assets Presented in the Statement of Financial Position	Gross Amount Not Offset in the Statement of Financial Position	Net Amount
	(in millions)				
Description:					
Derivatives	$ 119.9	$ (24.3)	$ 95.6	$ (18.6)	$ 77.0
Total	$ 119.9	$ (24.3)	$ 95.6	$ (18.6)	$ 77.0

Offsetting of Financial Liabilities and Derivative Liabilities

	As of September 30, 2014				
	Gross Amount of Recognized Liabilities	Gross Amount Offset in the Statement of Financial Position	Net Amount of Liabilities Presented in the Statement of Financial Position	Gross Amount Not Offset in the Statement of Financial Position	Net Amount
	(in millions)				
Description:					
Derivatives	$ (293.5)	$ —	$ (293.5)	$ 33.6	$(259.9)
Total	$ (293.5)	$ —	$ (293.5)	$ 33.6	$(259.9)

	As of December 31, 2013				
	Gross Amount of Recognized Liabilities	Gross Amount Offset in the Statement of Financial Position	Net Amount of Liabilities Presented in the Statement of Financial Position	Gross Amount Not Offset in the Statement of Financial Position	Net Amount
	(in millions)				
Description:					
Derivatives (1)	$ (208.6)	$ 24.3	$ (184.3)	$ 18.6	$(165.7)
Total	$ (208.6)	$ 24.3	$ (184.3)	$ 18.6	$(165.7)

(1) Includes $16.7 million of cash collateral at December 31, 2013.

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 September 30, 2014 and December 31, 2013. 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.

	September 30, 2014				December 31, 2013			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
	(in millions)							
Interest rate contracts (1)	$ —	$(245.9)	$ —	$(245.9)	$ —	$(96.4)	$ —	$(96.4)
Commodity contracts:								
Financial	—	12.1	1.8	13.9	—	6.4	(6.9)	(0.5)
Physical	—	—	7.6	7.6	—	—	(0.2)	(0.2)
Commodity options	—	—	5.3	5.3	—	—	8.4	8.4
Total	$ —	$(233.8)	$ 14.7	$(219.1)	$ —	$(90.0)	$ 1.3	$(88.7)

(1) During the period, there were no significant transfers in or out of any of any of the Levels or between Levels.

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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. An increase 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 September 30, 2014 (2) (in millions)	Valuation Technique	Unobservable Input	Range (1) Lowest	Range (1) Highest	Range (1) Weighted Average	Units
Commodity Contracts - Financial							
Natural Gas	$ (0.6)	Market Approach	Forward Gas Price	3.49	4.74	4.01	MMBtu
NGLs	$ 2.4	Market Approach	Forward NGL Price	0.24	1.98	1.18	Gal
Commodity Contracts - Physical							
Natural Gas	$ 1.8	Market Approach	Forward Gas Price	2.03	4.83	4.04	MMBtu
Crude Oil	$ (1.5)	Market Approach	Forward Crude Price	83.03	94.98	90.86	Bbl
NGLs	$ 7.4	Market Approach	Forward NGL Price	0.23	2.05	1.08	Gal
Power	$ (0.1)	Market Approach	Forward Power Price	36.21	39.49	37.84	MWh
Commodity Options							
Natural Gas, Crude and NGLs	$ 5.3	Option Model	Option Volatility	14%	40%	28%	
Total Fair Value	$ 14.7						

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

(2) Fair values include credit valuation adjustments of approximately $0.1 million of losses.

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Quantitative Information About Level 3 Fair Value Measurements

Contract Type	Fair Value at December 31, 2013 (2) (in millions)		Valuation Technique	Unobservable Input	Range (1) Lowest	Highest	Weighted Average	Units
Commodity Contracts - Financial								
Natural Gas	$	—	Market Approach	Forward Gas Price	3.64	4.41	4.14	MMBtu
NGLs	$	(6.9)	Market Approach	Forward NGL Price	1.00	2.13	1.38	Gal
Commodity Contracts - Physical								
Natural Gas	$	1.1	Market Approach	Forward Gas Price	3.36	4.82	4.15	MMBtu
Crude Oil	$	(0.5)	Market Approach	Forward Crude Oil Price	86.37	103.04	97.24	Bbl
NGLs	$	(0.1)	Market Approach	Forward NGL Price	0.02	2.19	0.95	Gal
Power	$	(0.7)	Market Approach	Forward Power Price	32.40	38.98	35.07	MWh
Commodity Options								
Natural Gas, Crude and NGLs	$	8.4	Option Model	Option Volatility	18%	44%	28%	
Total Fair Value	$	1.3						

(1) Prices are in dollars per Millions of British Thermal Units, or MMBtu, for Natural Gas; dollars per Gallon, or Gal, for NGLs; dollars per barrel, or Bbl, for Crude Oil; and dollars per Megawatt hour, or MWh, for Power.
(2) Fair values include credit valuation adjustments of approximately $0.1 million of gains.

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, 2014 to September 30, 2014. 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, 2014	$ (6.9)	$ (0.2)	$ 8.4	$ 1.3
Transfer in (out) of Level 3 (1)	—	—	—	—
Gains or losses:				
Included in earnings	(3.9)	11.1	(1.1)	6.1
Included in other comprehensive income	(0.2)	—	—	(0.2)
Purchases, issuances, sales and settlements:				
Purchases	—	—	0.4	0.4
Sales	—	—	(1.6)	(1.6)
Settlements (2)	12.8	(3.3)	(0.8)	8.7
Ending balance as September 30, 2014	$ 1.8	$ 7.6	$ 5.3	$14.7
Amount of changes in net assets attributable to the change in derivative gains or losses related to assets still held at the reporting date	$ 2.4	$ 7.2	$ (1.8)	$ 7.8
Amounts reported in operating revenue	$ —	$ 11.2	$ —	$ 11.2

(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.

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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 September 30, 2014 and December 31, 2013.

	At September 30, 2014						At December 31, 2013	
			Wtd. Average Price (2)		Fair Value (3)		Fair Value (3)	
	Commodity	Notional (1)	Receive	Pay	Asset	Liability	Asset	Liability
					(in millions)			
Portion of contracts maturing in 2014								
Swaps								
Receive variable/pay fixed	Natural Gas	668,692	$ 4.00	$ 3.91	$ 0.1	$ —	$ —	$ —
	NGL	623,000	$ 56.02	$ 56.64	$ 0.3	$ (0.7)	$ 0.6	$ (0.4)
	Crude Oil	95,000	$ 89.87	$ 92.56	$ —	$ (0.3)	$ —	$ —
Receive fixed/pay variable	Natural Gas	2,380,100	$ 4.26	$ 4.09	$ 0.5	$ (0.1)	$ 0.1	$ (1.0)
	NGL	2,021,140	$ 51.91	$ 50.97	$ 3.7	$ (1.8)	$ 4.8	$ (12.7)
	Crude Oil	457,764	$ 95.26	$ 90.14	$ 2.7	$ (0.4)	$ 3.4	$ (5.4)
Receive variable/pay variable	Natural Gas	19,562,500	$ 4.03	$ 4.02	$ 0.6	$ (0.5)	$ 0.6	$ (0.1)
Physical Contracts								
Receive variable/pay fixed	Natural Gas	313,224	$ 3.89	$ 1.23	$ 0.8	$ —	$ —	$ —
	NGL	550,000	$ 42.40	$ 43.88	$ —	$ (0.8)	$ 0.9	$ (0.9)
	Crude Oil	45,000	$ 90.85	$ 93.90	$ —	$ (0.1)	$ —	$ —
Receive fixed/pay variable	Natural Gas	185,506	$ 4.03	$ 3.97	$ —	$ —	$ —	$ —
	NGL	3,504,872	$ 39.20	$ 37.85	$ 5.1	$ (0.4)	$ 0.4	$ (2.6)
	Crude Oil	75,000	$ 93.08	$ 90.62	$ 0.2	$ —	$ —	$ (0.4)
Pay fixed	Power (4)	14,716	$ 37.84	$ 46.59	$ —	$ (0.1)	$ —	$ (0.7)
Receive variable/pay variable	Natural Gas	72,613,470	$ 4.02	$ 4.02	$ 0.9	$ (1.1)	$ 0.9	$ (0.4)
	NGL	10,947,422	$ 42.80	$ 42.61	$ 2.7	$ (0.6)	$ 5.8	$ (3.7)
	Crude Oil	758,914	$ 88.26	$ 90.52	$ 0.8	$ (2.5)	$ 1.1	$ (1.2)
Portion of contracts maturing in 2015								
Swaps								
Receive variable/pay fixed	Natural Gas	316,837	$ 3.91	$ 3.93	$ —	$ —	$ —	$ —
	NGL	145,850	$ 72.56	$ 78.20	$ —	$ (0.8)	$ —	$ —
	Crude Oil	456,000	$ 87.81	$ 92.94	$ —	$ (2.3)	$ —	$ —
Receive fixed/pay variable	Natural Gas	809,761	$ 4.56	$ 4.21	$ 0.3	$ —	$ —	$ —
	NGL	1,024,750	$ 54.42	$ 52.36	$ 3.1	$ (1.0)	$ 1.5	$ (1.1)
	Crude Oil	1,303,165	$ 96.75	$ 87.78	$11.7	$ —	$ 8.3	$ —
Receive variable/pay variable	Natural Gas	42,725,000	$ 3.92	$ 3.94	$ 0.8	$ (1.7)	$ 0.1	$ —
Physical Contracts								
Receive variable/pay fixed	NGL	95,000	$ 46.73	$ 48.37	$ —	$ (0.2)	$ —	$ —
Receive fixed/pay variable	NGL	586,394	$ 49.38	$ 47.79	$ 1.0	$ —	$ —	$ —
Receive variable/pay variable	Natural Gas	108,991,322	$ 4.05	$ 4.05	$ 1.4	$ (0.7)	$ 0.5	$ (0.1)
	NGL	3,094,719	$ 61.40	$ 61.19	$ 1.2	$ (0.5)	$ —	$ —
	Crude Oil	151,000	$ 90.30	$ 88.89	$ 0.2	$ —	$ —	$ —
Portion of contracts maturing in 2016								
Swaps								
Receive variable/pay fixed	Natural Gas	181,435	$ 3.78	$ 3.85	$ —	$ —	$ —	$ —
	Crude Oil	68,250	$ 86.36	$ 90.00	$ —	$ (0.2)	$ —	$ —
Receive fixed/pay variable	Crude Oil	68,250	$ 90.89	$ 86.36	$ 0.3	$ —	$ 0.7	$ —
Receive variable/pay variable	Natural Gas	12,027,000	$ 3.96	$ 3.98	$ 0.1	$ (0.3)	$ —	$ —
Physical Contracts								
Receive variable/pay variable	Natural Gas	34,560,879	$ 4.06	$ 4.05	$ 0.7	$ (0.4)	$ 0.1	$ —
Portion of contracts maturing in 2017								
Physical Contracts								
Receive variable/pay variable	Natural Gas	14,299,743	$ 4.27	$ 4.26	$ 0.2	$ (0.1)	$ —	$ —

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

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

(3) The fair value is determined based on quoted market prices at September 30, 2014 and December 31, 2013, 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 $0.1 million of gains at September 30, 2014 and December 31, 2013, respectively.

(4) For physical power, the receive price shown represents the index price used for valuation purposes.

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The following table provides summarized information about the fair values of expected cash flows of our outstanding commodity options at September 30, 2014 and December 31, 2013.

	At September 30, 2014						At December 31, 2013	
					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 2014								
Puts (purchased)	Natural Gas	1,104,000	$ 3.90	$ 4.10	$ 0.1	$ —	$ 0.7	$ —
	NGL	193,200	$54.79	$52.43	$ 0.9	$ —	$ 2.9	$ —
Calls (written)	NGL	115,000	$60.92	$54.59	$—	$ (0.1)	$ —	$ (1.0)
Puts (written)	Natural Gas	1,104,000	$ 3.90	$ 4.10	$—	$ (0.1)	$ —	$ (0.5)
	NGL	32,200	$66.36	$51.70	$—	$ (0.5)	$ —	$ —
Calls (purchased)	NGL	46,000	$50.40	$43.84	$—	$ —	$ —	$ —
Portion of option contracts maturing in 2015								
Puts (purchased)	Natural Gas	4,015,000	$ 3.90	$ 4.00	$ 1.4	$ —	$ 1.7	$ —
	NGL	1,350,500	$48.75	$50.62	$ 5.5	$ —	$ 6.0	$ —
	Crude Oil	547,500	$85.42	$87.76	$ 2.3	$ —	$ 1.8	$ —
Calls (written)	Natural Gas	1,277,500	$ 5.05	$ 4.00	$—	$ (0.1)	$ —	$ (0.3)
	NGL	529,250	$55.18	$50.29	$—	$ (1.7)	$ —	$ (1.0)
	Crude Oil	547,500	$91.75	$87.76	$—	$ (2.1)	$ —	$ (1.9)
Puts (written)	Natural Gas	4,015,000	$ 3.90	$ 4.00	$—	$ (1.4)	$ —	$ —
Calls (purchased)	Natural Gas	1,277,500	$ 5.05	$ 4.00	$ 0.1	$ —	$ —	$ —
Portion of option contracts maturing in 2016								
Puts (purchased)	Natural Gas	1,647,000	$ 3.75	$ 4.08	$ 0.5	$ —	$ —	$ —
	NGL	1,281,000	$41.82	$44.06	$ 6.5	$ —	$ —	$ —
	Crude Oil	439,200	$80.00	$85.93	$ 2.0	$ —	$ —	$ —
Calls (written)	Natural Gas	1,647,000	$ 4.98	$ 4.08	$—	$ (0.3)	$ —	$ —
	NGL	1,281,000	$48.59	$44.06	$—	$ (5.6)	$ —	$ —
	Crude Oil	439,200	$92.25	$85.93	$—	$ (2.2)	$ —	$ —

(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 September 30, 2014 and December 31, 2013, 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.

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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 September 30, 2014	Fair Value (2) at December 31, 2013
			(dollars in millions)		
Contracts maturing in 2015					
Interest Rate Swaps—Pay Fixed	Cash Flow Hedge	$ 510	1.53%	$ (1.9)	$ (6.8)
Contracts maturing in 2016					
Interest Rate Swaps—Pay Fixed	Cash Flow Hedge	$ 90	0.55%	$ —	—
Contracts maturing in 2017					
Interest Rate Swaps—Pay Fixed	Cash Flow Hedge	$ 450	2.21%	$ (12.2)	$ (13.8)
Contracts maturing in 2018					
Interest Rate Swaps—Pay Fixed	Cash Flow Hedge	$ 810	2.24%	$ 1.4	$ 3.3
Contracts maturing in 2019					
Interest Rate Swaps—Pay Fixed	Cash Flow Hedge	$ 620	2.96%	$ (1.0)	$ —
Contracts settling prior to maturity					
2014—Pre-issuance Hedges (3)	Cash Flow Hedge	$ —	0.00%	$ —	$ (132.7)
2015—Pre-issuance Hedges	Cash Flow Hedge	$1,000	5.48%	$ (208.5)	—
2016—Pre-issuance Hedges	Cash Flow Hedge	$ 500	4.21%	$ (38.0)	$ 60.8
2017—Pre-issuance Hedges	Cash Flow Hedge	$ 500	3.69%	$ (10.8)	—
2018—Pre-issuance Hedges	Cash Flow Hedge	$ 350	3.08%	$ 12.4	—

(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 September 30, 2014 and December 31, 2013, 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 $12.7 million of gains at September 30, 2014 and $7.1 million of losses at December 31, 2013.

(3) Includes $16.7 million of cash collateral at December 31, 2013.

11. 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. The Texas state income tax rate was 0.4% for the nine month periods ended September 30, 2014 and 2013. Our income tax expense is $2.1 million and $1.5 million, for the three month periods ended September 2014 and 2013, respectively, and $6.1 million and $17.5 million for the nine month periods ended September 30, 2014 and 2013, respectively.

At September 30, 2014 and December 31, 2013, we have included a current income tax payable of $1.1 million and $0.9 million, respectively, in “Property and other taxes payable” on our consolidated statements of financial position. In addition, at September 30, 2014 and December 31, 2013, we have included a deferred income tax payable of $19.0 million and $17.4 million, respectively, in “Deferred income tax liability,” 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.

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12. 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 is 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.

During the first quarter of 2014, we changed our reporting segments. The Marketing segment was combined with the Natural Gas segment to form one new segment called "Natural Gas". There was no change to the Liquids segment.

This change was a result of the reorganization of EEP resulting from MEP's IPO, which prompted Management to reassess the presentation of EEP's reportable segments considering the financial information available and evaluated regularly by EEP's Chief Operating Decision Maker. The new segment is consistent with how management makes resource allocation decisions, evaluates performance, and furthers the achievement of the Partnership's long-term objectives. Financial information for the prior periods has been restated to reflect the change in reporting segments.

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

	For the three month period ended September 30, 2014			
	Liquids	Natural Gas	Corporate (1)	Total
	(in millions)			
Operating revenue	$ 542.9	$ 1,399.4	$ —	$1,942.3
Cost of natural gas	—	1,238.2	—	1,238.2
Environmental costs, net of recoveries	50.1	—	—	50.1
Operating and administrative	126.5	105.0	3.8	235.3
Power	59.5	—	—	59.5
Depreciation and amortization	79.3	39.5	—	118.8
	315.4	1,382.7	3.8	1,701.9
Operating income (loss)	227.5	16.7	(3.8)	240.4
Interest expense, net	—	—	137.1	137.1
Allowance for equity used during construction	—	—	14.5	14.5
Other income (expense) (2)	—	6.1	(4.3)	1.8
Income (loss) before income tax expense	227.5	22.8	(130.7)	119.6
Income tax expense	—	—	2.1	2.1
Net income (loss)	227.5	22.8	(132.8)	117.5
Less: Net income attributable to:				
Noncontrolling interest	—	—	70.7	70.7
Series 1 preferred unit distributions	—	—	22.5	22.5
Accretion of discount on Series 1 preferred units	—	—	3.8	3.8
Net income (loss) attributable to general and limited partner ownership interests in Enbridge Energy Partners, L.P.	$ 227.5	$ 22.8	$ (229.8)	$ 20.5

(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.

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(2) Other income (expense) for our Natural Gas segment includes our equity investment in the Texas Express NGL system which we began recognizing operating costs during the fourth quarter of 2013.

	For the three month period ended September 30, 2013			
	Liquids	Natural Gas	Corporate (1)	Total
	(in millions)			
Operating revenue	$ 401.5	$ 1,387.9	$ —	$1,789.4
Cost of natural gas	—	1,257.5	—	1,257.5
Environmental costs, net of recoveries	0.6	—	—	0.6
Operating and administrative	149.7	113.6	1.8	265.1
Power	43.0	—	—	43.0
Depreciation and amortization	63.8	35.8	—	99.6
	257.1	1,406.9	1.8	1,665.8
Operating income (loss)	144.4	(19.0)	(1.8)	123.6
Interest expense, net	—	—	70.5	70.5
Allowance for equity used during construction	—	—	9.3	9.3
Other income	—	—	0.4	0.4
Income (loss) before income tax expense	144.4	(19.0)	(62.6)	62.8
Income tax expense	—	—	1.5	1.5
Net income (loss)	144.4	(19.0)	(64.1)	61.3
Less: Net income attributable to the noncontrolling interest	—	—	20.3	20.3
Series 1 preferred unit distributions	—	—	22.7	22.7
Accretion of discount on Series 1 preferred units	—	—	3.4	3.4
Net income (loss) attributable to general and limited partner ownership interests in Enbridge Energy Partners, L.P.	$ 144.4	$ (19.0)	$ (110.5)	$ 14.9

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

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	As of and for the nine month period ended September 30, 2014			
	Liquids	Natural Gas	Corporate (1)	Total
	(in millions)			
Operating revenue	$ 1,449.9	$ 4,443.1	$ —	$ 5,893.0
Cost of natural gas	—	3,986.7	—	3,986.7
Environmental costs, net of recoveries	93.3	—	—	93.3
Operating and administrative	352.5	317.5	6.9	676.9
Power	164.1	—	—	164.1
Depreciation and amortization	222.7	113.3	—	336.0
	832.6	4,417.5	6.9	5,257.0
Operating income (loss)	617.3	25.6	(6.9)	636.0
Interest expense, net	—	—	294.2	294.2
Allowance for equity used during construction	—	—	47.8	47.8
Other income (expense)	—	7.1 (2)	(4.9)	2.2
Income (loss) before income tax expense	617.3	32.7	(258.2)	391.8
Income tax expense	—	—	6.1	6.1
Net income (loss)	617.3	32.7	(264.3)	385.7
Less: Net income attributable to:				
Noncontrolling interest	—	—	149.4	149.4
Series 1 preferred unit distributions	—	—	67.5	67.5
Accretion of discount on Series 1 preferred units	—	—	11.1	11.1
Net income (loss) attributable to general and limited partner ownership interests in Enbridge Energy Partners, L.P.	$ 617.3	$ 32.7	$ (492.3)	$ 157.7
Total assets	$ 11,252.8	$ 5,461.9 (3)	$ 232.4	$16,947.1
Capital expenditures (excluding acquisitions)	$ 1,861.3	$ 158.4	$ 3.2	$ 2,022.9

(1) Corporate consists of interest expense, interest income, allowance for equity used during construction, noncontrolling interest and other costs such as income taxes, which are not allocated to the business segments.
(2) Other income (expense) for our Natural Gas segment includes our equity investment in the Texas Express NGL system which began recognizing operating costs during the fourth quarter of 2013.
(3) Total assets for our Natural Gas segment includes our long term equity investment in the Texas Express NGL system.

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	As of and for the nine month period ended September 30, 2013			
	Liquids	Natural Gas	Corporate (1)	Total
	(in millions)			
Operating revenue	$ 1,100.7	$ 4,054.4	$ —	$ 5,155.1
Cost of natural gas	—	3,564.4	—	3,564.4
Environmental costs, net of recoveries	184.3	—	—	184.3
Operating and administrative	334.8	337.8	5.4	678.0
Power	105.8	—	—	105.8
Depreciation and amortization	181.0	106.6	—	287.6
	805.9	4,008.8	5.4	4,820.1
Operating income (loss)	294.8	45.6	(5.4)	335.0
Interest expense, net	—	—	226.4	226.4
Allowance for equity used during construction	—	—	25.2	25.2
Other income	—	—	1.0	1.0
Income (loss) before income tax expense	294.8	45.6	(205.6)	134.8
Income tax expense	—	—	17.5	17.5
Net income (loss)	294.8	45.6	(223.1)	117.3
Less: Net income attributable to the noncontrolling interest	—	—	54.3	54.3
Series 1 preferred unit distributions	—	—	35.8	35.8
Accretion of discount on Series 1 preferred units	—	—	5.7	5.7
Net income (loss) attributable to general and limited partner ownership interests in Enbridge Energy Partners, L.P.	$ 294.8	$ 45.6	$ (318.9)	$ 21.5
Total assets	$ 8,497.9	$ 5,224.6 (2)	$ 161.5	$13,884.0
Capital expenditures (excluding acquisitions)	$ 1,527.2	$ 191.9	$ 13.9	$ 1,733.0

(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 assets for our Natural Gas segment includes our long term equity investment in the Texas Express NGL system.

13. 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 of rates in any given year. These over or under recoveries of rates are returned to shippers or recovered by us 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.

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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. As of September 30, 2014 and December 31, 2013, we had a net regulatory liability balance of $5.6 million and a net regulatory asset balance of $7.7 million, respectively.

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 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. Our over and under recovery revenue adjustments and net regulatory asset amortization for the three and nine months ended September 30, 2014 and 2013 are as follows:

	For the three month period ended September 30,		For the nine month period ended September 30,	
	2014	2013	2014	2013
	(in millions)		(in millions)	
Current Year (Over)/Under Recovery Revenue Adjustments	$ (4.5)	$ 3.2	$ (5.6)	$ 7.7
Amortization of Prior Year Regulatory (Asset)/Liability	—	3.8	(7.7) (1)	11.5

(1) The amortization of the prior year regulatory asset for the nine month period ended September 30, 2014, includes a $7.6 million adjustment of the regulatory asset for the difference between estimates as of December 31, 2013, and actual data received during the nine month period ended September 30, 2014.

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. The amortization for this contractual obligation reflects the related transportation rate adjustment in the subsequent year. At September 30, 2014, we had no qualifying volume liabilities related to the Southern Access Pipeline on our statements of financial position. At December 31, 2013, we had $6.1 million in qualifying volume liabilities related to the Southern Access Pipeline on our statements of financial position. For the nine month periods ended September 30, 2014 and 2013, we increased our revenues by $6.1 million and $4.2 million, respectively, on our consolidated statements of income with a corresponding amount reducing the contractual obligation on our consolidated statements of financial position to account for amortization of the liability.

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. At September 30, 2014 and December 31, 2013, we had $6.3 million and $6.9 million, respectively, in property tax over recovery liabilities related to our Alberta Clipper Pipeline on our statements of financial position.

For 2013, we also incurred liabilities related to this contractual obligation on the Alberta Clipper Pipeline. As a result, in 2013, we reduced revenues for the amounts due back to our shippers and recorded a liability for the contractual obligation. We amortize the liability on a straight line basis in the following year. For the nine month periods ended September 30, 2014 and 2013, we increased our revenues by $5.2 million and $4.5 million, respectively, on our consolidated statements of income with a corresponding amount reducing the contractual obligation on our consolidated statements of financial position.

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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 6B 75-mile Replacement and Mainline Expansion Projects, we recorded $14.5 and $47.8 million of "Allowance for equity used during construction" in our consolidated statement of income for the three and nine month period ended September 30, 2014, respectively, and a corresponding amount of $47.8 million of AEDC in "Property, plant and equipment" on our consolidated statement of financial position at September 30, 2014. We recorded $9.3 million and $25.2 million of "Allowance for equity used during construction" in our consolidated statements of income for the three and nine month period ended September 30, 2013, respectively, and a corresponding amount of $25.2 million of AEDC in "Property, plant and equipment" on our consolidated statement of financial position at September 30, 2013.

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 nine month period ended September 30,	
	2014	2013
	(in millions)	
Additions to property, plant and equipment	$ 2,055.8	$ 1,514.5
Increase (decrease) in construction payables	(32.9)	218.5
Total capital expenditures (excluding "Investment in joint venture")	$ 2,022.9	$ 1,733.0

15. RECENT ACCOUNTING PRONOUNCEMENTS NOT YET ADOPTED

In April 2014, the Financial Accounting Standards Board, or FASB, issued Accounting Standards Update No. 2014-08 that changes the criteria and requires expanded disclosures for reporting discontinued operations. This accounting update is effective for annual and interim periods beginning after December 15, 2014 and is to be applied prospectively. We do not expect that the adoption of this pronouncement will have a material impact on our consolidated financial statements.

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.

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 beginning on or 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.

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16. SUBSEQUENT EVENTS

Credit Facility Agreement Amendments

On October 6, 2014, we amended the Credit Facility to extend the maturity date from September 26, 2018 to September 26, 2019; however, $175.0 million of commitments will expire on the original maturity date of September 26, 2018.

Distribution to Partners

On October 31, 2014, the board of directors of Enbridge Management declared a distribution payable to our partners on November 14, 2014. The distribution will be paid to unitholders of record as of November 7, 2014 of our available cash of $221.8 million at September 30, 2014, or $0.5550 per limited partner unit. Of this distribution, $183.7 million will be paid in cash, $37.3 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 AC Interests

On October 31, 2014, 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 AC interests, declared a distribution payable to the holders of the Series AC general and limited partner interests. The OLP will pay $20.3 million to the noncontrolling interest in the Series AC, while $10.1 million will be paid to us.

Distribution to Series EA Interests

On October 31, 2014, 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 $43.7 million to the noncontrolling interest in the Series EA, while $14.6 million will be paid to us.

Distribution to Series ME Interests

On October 31, 2014, 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 $1.9 million to the noncontrolling interest in the Series ME, while $0.6 million will be paid to us.

Distribution from MEP

On October 30, 2014, 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 their partners on November 14, 2014. The distribution will be paid to unitholders of record as of November 7, 2014, of MEP's available cash of $15.6 million at September 30, 2014, or $0.3375 per limited partner unit. MEP will pay $7.2 million to their public Class A common unitholders, while $8.4 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 October 30, 2014, the general partner of Midcoast Operating, acting in its capacity as the general partner of Midcoast Operating, declared a cash distribution by Midcoast Operating payable to its partners of record as of November 7, 2014. Midcoast Operating will pay $12.6 million to us and $13.5 million to MEP.

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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.

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;
- Gathering, treating, processing and transportation of natural gas and natural gas liquids, or NGLs, through pipelines and related facilities; and
- 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. During the first quarter of 2014, we changed our reporting segments. The Marketing segment was combined with the Natural Gas segment to form one new segment named "Natural Gas". There was no change to the Liquids segment.

This change was a result of the reorganization of EEP in connection with MEP's IPO which prompted management to reassess the presentation of EEP's reportable segments considering the financial information available and evaluated regularly by EEP's Chief Operating Decision Maker. The new segment is consistent with how management makes resource allocation decisions, evaluates performance, and furthers the achievement of the Partnership's long-term objectives. Financial information for the prior periods has been restated to reflect the change in reporting segments.

The following table reflects our operating income by business segment and corporate charges for each of the three and nine month periods ended September 30, 2014 and 2013.

	For the three month period ended September 30,		For the nine month period ended September 30,	
	2014	2013	2014	2013
	(in millions)			
Operating income (loss)				
Liquids	$ 227.5	$ 144.4	$ 617.3	$ 294.8
Natural Gas	16.7	(19.0)	25.6	45.6
Corporate, operating and administrative	(3.8)	(1.8)	(6.9)	(5.4)
Total operating income	240.4	123.6	636.0	335.0
Interest expense	137.1	70.5	294.2	226.4
Allowance for equity used during construction	14.5	9.3	47.8	25.2
Other income	1.8	0.4	2.2	1.0
Income before income tax expense	119.6	62.8	391.8	134.8
Income tax expense	2.1	1.5	6.1	17.5
Net income	117.5	61.3	385.7	117.3
Less: Net income attributable to:				
Noncontrolling interest	70.7	20.3	149.4	54.3
Series 1 preferred unit distributions	22.5	22.7	67.5	35.8
Accretion of discount on Series 1 preferred units	3.8	3.4	11.1	5.7
Net income attributable to general and limited partner ownership interests in Enbridge Energy Partners, L.P.	$ 20.5	$ 14.9	$ 157.7	$ 21.5

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Contractual arrangements in our Liquids and Natural Gas segments expose us to market risks associated with changes in 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. Our unhedged commodity position is fully exposed to fluctuations in commodity prices. These fluctuations can be significant if commodity prices experience significant volatility. We employ derivative financial instruments to hedge a portion of our commodity position and to reduce our exposure to fluctuations in crude oil, natural gas and NGL prices. Some of these derivative financial instruments do not qualify for hedge accounting under the provisions of authoritative accounting guidance, which can create volatility in our earnings that can be significant. However, these fluctuations in earnings do not affect our cash flow. Cash flow is only affected when we settle the derivative instrument.

Summary Analysis of Operating Results

Liquids

The following factors primarily affected the $83.1 million and the $322.5 million increases in operating income for the three and nine month periods ended September 30, 2014, respectively, when compared to the same period of 2013:

- Increased revenue of $78.6 million and $203.5 million for the three and nine month periods ended September 30, 2014, respectively, related to rate increases as a result of tariff filings that became effective July 1 and August 1, 2014. Operating revenue on our Lakehead system was offset by $17.7 million and $46.3 million for the three and nine month periods ended September 30, 2014, respectively, related to regulatory true-ups on Lakehead toll revenues;
- Decreased environmental expense of $91.0 million for the nine month period ended September 30, 2014 as compared with the same period in 2013, primarily due to lower environmental accruals, net of recoveries, related to the Line 6B crude oil release recognized in the second quarter of 2013;
- Increased volumes on our Lakehead and North Dakota systems increased revenue by $57.4 million and $145.4 million for the three and nine month periods ended September 30, 2014, respectively, when compared to the same periods in 2013;
- Increased revenue from our ship or pay agreements of $5.3 million and $17.8 million on our North Dakota Bakken system for the three and nine month period ended September 30, 2014, respectively;
- Increased rail revenue of $2.5 million and $15.4 million for the three and nine month periods ended September 30, 2014, respectively, on our Berthold Rail system which was placed in service in March of 2013;
- Increased non-cash, mark-to-market net gains of $12.0 million related to derivative financial instruments for the three month period ended September 30, 2014. The increase is the result of $4.0 million in realized gains related to our settled derivative financial instruments, coupled with $8.0 million of non-cash, mark-to-market net gains due to decreases in average forward prices of crude oil during the three month period ended September 30, 2014 compared to increases in the average forward prices of crude oil during the same period in 2013; and
- Decreased operating and administrative expenses of $23.2 million for the three month period ended September 30, 2014, primarily due to a decrease of $45.3 million of pipeline integrity costs. This decrease was offset by increases of $8.2 million in operational costs, $6.7 million of workforce related costs, and $5.7 million of property taxes. The decreased pipeline integrity costs is primarily due to costs incurred in the third quarter of 2013 for the Line 14 hydrostatic test that was not repeated in the third quarter of 2014. The increase in the other aforementioned operating and administrative costs are attributable to additional assets placed into service.

The increase in operating income was partially offset by the following factors:

- Increased operating and administrative expenses of $17.7 million for the nine month period ended September 30, 2014, when compared to the same period in 2013. This is due to increases of $16.5

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million in operational costs, $29.0 million of workforce related costs, and $13.5 million of property taxes. These costs increases were offset by $40.6 million of lower pipeline integrity costs. The decrease in pipeline integrity costs is primarily due to the aforementioned Line 14 hydrostatic test conducted in the third quarter of 2013 that was not repeated in 2014. The increase in the other operating and administrative costs is primarily the result of additional assets placed into service;

- Increased environmental expense of $49.5 million for the three month period ended September 30, 2014 as compared with the same period in 2013, primarily due to activities performed as part of the Michigan Department of Environmental Quality, or MDEQ, approved Schedule of Work, completion of the dredge activities near Ceresco and Morrow Lake, and estimated civil penalties;
- Increased power costs of $16.5 million and $58.3 million for the three and nine month periods ended September 30, 2014, respectively, as compared to the same periods in 2013. This is due to an increase in volumes on our system; and
- Increased depreciation expense of $15.5 million and $41.7 million for the three and nine month periods ended September 30, 2014, respectively, when compared to the same periods in 2013, directly attributable to additional assets placed into service.

Natural Gas

The operating income of our Natural Gas business increased $35.7 million and decreased $20.0 million for the three and nine month periods ended September 30, 2014, respectively, when compared to the same periods in 2013, primarily due to the following:

- Decreased operating income of approximately $15.0 million and $42.9 million for the three and nine month periods ended September 30, 2014, respectively, when compared to the same periods in 2013, due to reduced average daily volumes on our major systems primarily attributable to the loss of a major customer on our Anadarko system and reduced and delayed drilling activity by certain producers. The decrease in volumes in the East Texas region was primarily attributable to reduced dry gas drilling, and delayed drilling activity and well completions;
- Operating and administrative costs decreased $8.6 million and $20.3 million for the three and nine month periods ended September 30, 2014, respectively, when compared to the same periods in 2013, due partly to lower volumes received from our Natural Gas segment and partly due to a strategic reduction of long hauls due to new geographically advantaged sales points;
- Segment gross margin decreased as a result of lower storage margins of $7.4 million and $12.3 million for the three and nine month periods ended September 30, 2014, respectively, when compared to the same periods in 2013, and by an increase in cost of sales of $4.1 million for the three month period ended September 30, 2014, due to higher transportation and fractionation fees, freight costs, and product purchase costs, when compared to the same period in 2013;
- Decreased operating revenue less the cost of natural gas derived from keep-whole processing earnings for the three and nine month periods ended September 30, 2014, of $7.1 million and $19.0 million, respectively, when compared to the same periods in 2013, due to a lower volumes in keep-whole barrels in the Oklahoma and North Texas regions;
- Decreased operating income of approximately $3.0 million for the nine month period ended September 30, 2014, when compared to the same period in 2013, primarily due to the impact of sustained freezing temperatures which significantly disrupted producer well head production levels and our pipeline operations; and
- Decreased operating income of $1.5 million and $3.7 million for the three and nine month periods ended September 30, 2014, respectively, due to reduced pricing spreads between our Conway and Mont Belvieu market hubs when compared with the same periods in 2013.

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The above factors were partially offset for the three and nine month periods ended September 30, 2014, as compared with the same periods in 2013 primarily due to:

- Increased operating income of $50.2 million and $23.2 million for the three and nine month periods ended September 30, 2014, respectively, when compared to the same periods in 2013, due to non-cash, mark-to-market net losses from derivative instruments that do not qualify for hedge accounting treatment;
- Segment gross margin increased $2.4 million and $8.9 million for the three and nine month periods ended September 30, 2014, as compared with the same periods in 2013 due to increased margins from pricing differentials. Higher operating income for the nine month period ended September 30, 2014, was predominately due to strong natural gas marketing optimization results attributable to seasonal demand for natural gas deliveries from Mid-Continent to the Midwest market. We benefited from the natural gas pricing difference between market centers in the Mid-Continent supply areas and market area in the Midwest, which arose from higher than normal demand from winter weather in the Midwest;
- Increased operating revenues of $2.5 million and $6.9 million for the three and nine month periods ended September 30, 2014, related to contractual minimum volume commitment contracts in which our customer has not moved the required volumes; and
- Increased depreciation and amortization expense of $3.7 million and $6.7 million for the three and nine month periods ended September 30, 2014, respectively, as compared with the same periods in 2013, due to additional assets that were put in service.

Derivative Transactions and Hedging 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 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—"Operating revenue" and "Power"
- Natural Gas segment commodity-based derivatives—"Operating revenue" and "Cost of natural gas"
- Corporate interest rate derivatives—"Interest expense"

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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 September 30, 2014	For the three month period ended September 30, 2013	For the nine month period ended September 30, 2014	For the nine month period ended September 30, 2013
	(in millions)			
Liquids segment				
Non-qualified hedges	$ 6.5	$ (5.5)	$ (1.0)	$ (4.3)
Natural Gas segment				
Hedge ineffectiveness	0.9	(0.5)	1.5	1.8
Non-qualified hedges	16.8	(32.0)	10.0	(13.5)
Commodity derivative fair value net gains (losses)	24.2	(38.0)	10.5	(16.0)
Corporate				
Hedge ineffectiveness	(62.2)	(1.1)	(73.2)	(0.5)
Non-qualified interest rate hedges	—	—	—	(0.3)
Derivative fair value net gains (losses)	$ (38.0)	$ (39.1)	$ (62.7)	$ (16.8)

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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 September 30,		For the nine month period ended September 30,	
	2014	2013	2014	2013
	(in millions)			
Operating Results:				
Operating revenue	$ 542.9	$ 401.5	$ 1,449.9	$ 1,100.7
Environmental costs, net of recoveries	50.1	0.6	93.3	184.3
Operating and administrative	126.5	149.7	352.5	334.8
Power	59.5	43.0	164.1	105.8
Depreciation and amortization	79.3	63.8	222.7	181.0
Operating expenses	315.4	257.1	832.6	805.9
Operating income	$ 227.5	$ 144.4	$ 617.3	$ 294.8
Operating Statistics				
Lakehead system:				
United States (1)	1,711	1,430	1,635	1,393
Province of Ontario (1)	461	395	453	388
Total Lakehead system deliveries (1)	2,172	1,825	2,088	1,781
Barrel miles (billions)	152	124	430	357
Average haul (miles)	758	739	755	735
Mid-Continent system deliveries (1)	191	216	193	202
North Dakota system:				
Trunkline (1)	345	202	300	158
Gathering (1)	2	4	3	3
Total North Dakota system deliveries (1)	347	206	303	161
Total Liquids Segment Delivery Volumes (1)	2,710	2,247	2,584	2,144

(1) Average barrels per day in thousands.

Three month period ended September 30, 2014 compared with the three month period ended September 30, 2013

The operating revenue of our Liquids segment increased $141.4 million for the three month period ended September 30, 2014 when compared with the same period in 2013, primarily due to (1) increased tariff rates that became effective with the Federal Energy Regulatory Commission, or FERC, on August 1, 2014 for our Lakehead system, and on July 1, 2014 for our North Dakota and Ozark systems, (2) an increase in volumes on our systems, and (3) non-cash mark-to-market gains.

The increase in tariff rates accounted for $78.6 million of the increase in operating revenue for the three month period ended September 30, 2014 when compared to September 30, 2013.

The increase in tariff rates was offset by a $17.7 million decrease in revenues as a result of regulatory true-ups related to Lakehead toll revenues. The Lakehead tariff that became effective on August 1, 2014 eliminated

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the System Expansion Project II, or SEP II, surcharge that accounted for a large part of this decrease. The decrease was due to an over-collection of revenues on 2013 rates containing provisions that were not applicable under the newly negotiated agreement. Generally, these rates would have been updated on April 1 as part of the annual tariff filing. However, the renegotiation and delay in the annual filing for the Lakehead system resulted in an over-collection on SEP II. This newly negotiated agreement eliminated the SEP II surcharge, but adds new Facility Surcharge Mechanism, or FSM, rate components to recover the remaining Line 14 rate base, Legacy Integrity costs, and 50% of Future Agreed-Upon Integrity costs. The FSM revenue requirement for 2014 will be recovered over a five month period from August to December versus the usual nine month period from April to December as done in the typical Lakehead FSM filing schedule. This shortened recovery caused the rates to increase by approximately 4.6% over what they would have been if the rates were effective on April 1.

The North Dakota and Ozark systems tariffs that became effective on July 1, 2014 consisted of an annual indexing adjustment to the base rates in compliance with rate ceilings allowed by FERC.

Operating revenue of our Liquids segment increased for the three month period ended September 30, 2014 when compared with the same period in 2013 by $57.4 million due to higher average daily delivery volumes on our Lakehead and North Dakota systems. Average daily volumes delivered increased 463,000 barrels per day during the three month period ended September 30, 2014 compared to the three month period ended September 30, 2013. Of that amount, our Lakehead system realized higher daily volumes of approximately 347,000 barrels per day, which contributed to increased revenue of $43.9 million for the Lakehead system. This increase in volumes was in large part due to additional assets being placed into service, including the Line 6B replacement and various subcomponents of the Eastern Access and Mainline Expansion projects. The North Dakota system also experienced an increase of 141,000 barrels per day due to favorable market pricing differentials between the East coast and Gulf coast markets.

Additionally, our operating revenue increased for the three month period ended September 30, 2014, when compared to the same period in 2013, due to an increase of $2.5 million from our Berthold Rail and North Dakota Storage Systems. The Berthold Rail increase primarily results from higher average daily delivered rail volumes when compared to the same period last year. The revenue increase from the prior year reflects the placement of North Dakota Storage tanks into service during the fourth quarter of 2013. Moreover, operating revenue for the three month period ended September 30, 2014 increased by $5.3 million due to related ship-or-pay contracts on our Bakken system. This is primarily due to increased committed volumes for certain shippers. These long-term ship-or-pay contracts contain make-up rights. Make-up rights are granted when minimum volume commitments are not utilized during the period but under certain circumstances can be used to offset overages in future periods, subject to expiration periods. We recognize revenue associated with make-up rights at the earlier of when the make-up volume is shipped, the make-up right expires, or when it is determined that the likelihood that the shipper will utilize the make-up right is remote.

Lastly, our operating revenue increased during the three month period ended September 30, 2014, when compared to the same period in 2013, due to increases of $12.0 million of non-cash, mark-to-market net gains related to derivative financial instruments. The increase is the result of $4.0 million in realized gains related to our settled derivative financial instruments, coupled with $8.0 million of non-cash, mark-to-market net gains due to decreases in average forward prices of crude oil during the three month period ended September 30, 2014 compared to increases in the average forward prices of crude oil during the same period in 2013. We use forward contracts to hedge a portion of the crude oil we expect to receive from our customers as a pipeline loss allowance as part of the transportation of their crude oil. We subsequently sell this crude oil at market rates. We use derivative financial instruments which fix the sales price we will receive in the future for the sale of this crude oil. We elected not to designate these derivative financial instruments as cash flow hedges.

Environmental costs, net of recoveries, increased $49.5 million for the three month period ended September 30, 2014 when compared with the same period in 2013 due to $50.9 million in cost accruals related to the remediation of the Line 6B crude oil release. These costs accruals were mostly driven by activities performed

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as part of the Michigan Department of Environmental Quality, or MDEQ, approved Schedule of Work, completion of the dredge activities near Ceresco and Morrow Lake, and estimated civil penalties under the Clean Water Act of the United States. During the three month period ended September 30, 2013 there were no environmental costs or insurance recoveries related to the Line 6B crude oil release.

The operating and administrative expenses of our Liquids segment decreased $23.2 million for the three month period ended September 30, 2014 when compared with the same period in 2013, primarily due to a decrease of $45.3 million in pipeline integrity costs related to the Line 14 hydrostatic test. This decrease was offset by increased costs of: $8.2 million of operational costs, primarily consisting of contract labor, repairs and maintenance, and professional and regulatory services; $6.7 million related to workforce expenses; and $5.7 million of property taxes. The decrease in pipeline integrity costs is primarily due to costs incurred for the aforementioned hydrostatic test we performed on Line 14 during the third quarter of 2013 that was not repeated during the third quarter of 2014. The increase in the other aforementioned operating and administrative costs are primarily the result of additional assets placed into service during the period as discussed above.

Power costs increased $16.5 million for the three month period ended September 30, 2014 when compared to the same period in 2013 primarily as a result of increased volumes.

The increase in depreciation expense of $15.5 million for the three month period ended September 30, 2014 is directly attributable to the additional assets we have placed in service since the three month period ended September 30, 2013, primarily on projects discussed above.

Nine month period ended September 30, 2014 compared with nine month period ended September 30, 2013

Our Liquids segment contributed $617.3 million of operating income during the nine month period ended September 30, 2014, representing a $322.5 million increase over the $294.8 million operating income for the same period in 2013. The components comprising the operating income of our Liquids business, such as operating revenue, operating and administrative expenses, power costs, and depreciation expenses changed during the nine month period ended September 30, 2014, as compared with the same period in 2013, primarily for the reasons noted above in our three month analysis in addition to the items noted below.

Operating revenue increased by $349.2 million for the nine month period ended September 30, 2014, when compared with the same period in 2013, primarily due to increases in tariff rates, delivery volumes and rail revenue as discussed in our analysis above. In addition, operating revenue for the nine month period ended September 30, 2014 improved due to increased revenues associated with ship or pay contracts on our Bakken system of $17.8 million. This is due to a full nine months of earnings from the Bakken system which went into service in March of 2013, as well as increased committed volumes for certain shippers.

Environmental costs, net of recoveries decreased $91.0 million for the nine month period ended September 30, 2014, when compared with the same period in 2013, which is primarily attributable to the change in cost accruals and insurance recoveries for Line 6B as discussed above. During the nine month period ended September 30, 2014 there were $85.9 million in cost accruals compared to $215.0 million accruals for the comparable period ended September 30, 2013. There were no insurance recoveries for the nine month period ended September 30, 2014 compared to $42.0 million in insurance recoveries for the comparable period ended September 30, 2013.

The operating and administrative expenses of our Liquids segment increased $17.7 million for the nine month period ended September 30, 2014 when compared with the same period in 2013. The increase is primarily due to: $16.5 million of operational costs, primarily consisting of contract labor, insurance, rent and leases, and professional and regulatory services; $29.0 million of workforce related costs; and $13.5 million of property taxes. The increase is offset by a decrease of $40.6 million of pipeline integrity costs primarily due to the

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previously mentioned hydrostatic test we performed during the third quarter of 2013 that was not repeated during the third quarter of 2014. The increase in the other aforementioned operating and administrative costs are primarily the result of additional assets placed into service during the period, including the Line 6B 75-mile Replacement and various subcomponents of the Eastern Access and Mainline Expansion projects.

Future Prospects Update for Liquids

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
Eastern Access Projects:			
Line 5, Line 62 Expansion, Line 6B Replacement	$ 2,400	2013—2014 (4)	Joint (1)
Eastern Access Upsize—Line 6B Expansion	310	Early 2016	Joint (1)
U.S. Mainline Expansions:			
Line 61 (ME phase 1)	160	Q3 2014	Joint (2)
Line 67 (ME phase 1)	220	Q3 2014 (3)	Joint (2)
Chicago Area Connectivity (Line 62 twin)	495	Q3 2015	Joint (2)
Line 61 (ME phase 2)	1,160	2015—2016	Joint (2)
Line 67 (ME phase 3)	240	Q3 2015	Joint (2)
Line 6B 75-mile Replacement Program	390	Q2 2013—Q1 2014	EEP
Sandpiper Project	2,600	2017	Joint (5)
Line 3 Replacement Program	2,600	Late 2017	EEP (6)

(1) 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.
(2) 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.
(3) A number of temporary system optimization actions have been undertaken to substantially mitigate any impact on throughput associated with the delays in regulatory approvals for the cross border expansion.
(4) As of September 30, 2014, all projects in this phase have been put into service.
(5) Since November 25, 2013, 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.
(6) A special committee of independent directors of the Board of EEP has been established to consider a joint funding agreement with Enbridge Inc.

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 to optimize throughput. The L3R Program is expected to achieve an equivalent 34-inch diameter pipeline capacity of approximately 760,000 bpd, which will enhance the flexibility and reliability of the Enbridge mainline system's over Western Canada export capacity.

The initial term of the agreement 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

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directors of the board of EEP 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 OLP similar to the series established for Alberta Clipper, Eastern Access and Mainline Expansion.

Line 6B 75-mile Replacement Program

In 2011, we announced plans to replace 75-miles of non-contiguous sections of Line 6B of our Lakehead system. Our Line 6B pipeline runs from Griffith, Indiana through Michigan to the international border at the St. Clair River. The new segments have been completed in components, with approximately 65 miles of segments placed in service in 2013. The two remaining 5-mile segments in Indiana were placed in service in March 2014. The total capital for this replacement program was approximately $390 million. These costs are currently being recovered through our FSM.

Light Oil Market Access Program

On December 6, 2012, we and Enbridge announced our plans to invest 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.

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, formerly known as Enbridge Pipelines (North Dakota) LLC, 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. Previously, we stated that the estimated target in-service date for our Sandpiper pipeline project would be in early 2016. We now estimate that the in-service date for the Sandpiper pipeline project will occur during 2017, subject to obtaining regulatory and other approvals. The delay is a result of a longer than expected permitting process in the State of Minnesota.

We filed a petition with the FERC to approve recovering Sandpiper's costs through a surcharge to the NDPC rates between Beaver Lodge and Clearbrook and a cost of service structure for rates between Clearbrook and Superior. In March 2013, the FERC denied the petition on procedural grounds. We refiled the petition on

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February 12, 2014 and received approval in the form of a declaratory order from the FERC on May 16, 2014. Furthermore, in late 2013, we held an open season to solicit commitments from shippers for capacity created by the Sandpiper Project. The open season closed in late January 2014 with the receipt of a further capacity commitment which can be accommodated within the planned incremental capacity as identified above.

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. In 2013, we completed and placed into service the 50,000 Bpd capacity expansion of our Line 5 light crude line between Superior, Wisconsin and the international border at the St. Clair River. Furthermore in 2013, we completed and placed into service the expansion of the Spearhead North pipeline, or Line 62 expansion, between Flanagan, Illinois and the Terminal at Griffith, Indiana. The Line 62 expansion increased capacity from 130,000 Bpd to 235,000 Bpd by adding horsepower.

In 2012, we announced plans to replace additional sections of the our Line 6B in Indiana and Michigan, referred to as the Line 6B Replacement project, including the addition of new pumps and terminal upgrades at Hartsdale, Griffith and Stockbridge, as well as tanks at Flanagan, Stockbridge and Hartsdale, to increase capacity from 240,000 Bpd to 500,000 Bpd. The replacement of the Line 6B sections are in addition to the line 6B 75-Mile Replacement Program discussed above. Portions of the existing 30-inch diameter pipeline have been replaced with 36-inch diameter pipe. The target in-service date for the Line 6B Replacement project was split into two phases, with the segment between Griffith and Stockbridge completed in May 2014 and the segment from Ortonville, Michigan to the international border at the St. Clair River completed in September 2014. These completed projects cost us approximately $2.4 billion and are being undertaken on a cost-of-service basis with shared capital cost risk, such that the toll surcharge will absorb 50% of any cost overruns over $1.85 billion during the Competitive Toll Settlement, or CTS, term, which runs until July 2021.

As part of the Light Oil Market Access Program announced in 2012, we announced a further expansion project of Line 6B to increase capacity from 500,000 Bpd to 570,000 Bpd and will 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, which is a decrease of $55 million from the original estimated cost as a result of a more detailed engineering estimate and a proposed tank construction being removed from the scope of the project. This further expansion of Line 6B is expected to begin service in early 2016.

These projects, collectively referred to as the Eastern Access Projects, will cost approximately $2.7 billion. The Eastern Access Projects are now being funded at 75% by our General Partner and 25% by us under the Eastern Access Joint Funding Agreement, after we exercised the option to reduce our portion of the funding by 15 percentage points on June 28, 2013. Additionally, within one year of the in-service date, scheduled for early 2016, we will have the option to increase our economic interest by up to 15 percentage points 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 76-mile, 36-inch diameter twin of the Spearhead North pipeline, or Line 62.

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 at an estimated cost of approximately $220 million, while the second phase will add an additional 230,000 Bpd of capacity at an

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estimated cost of approximately $240 million. 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. It is anticipated that obtaining regulatory approval for the expansion to 800,000 Bpd will take longer than originally planned although approval is expected mid-2015. A number of temporary system optimization actions have been undertaken to substantially mitigate any impact on throughput associated with the delays in regulatory approvals for the cross border expansion.

The current scope of the Southern Access expansion between Superior, Wisconsin and Flanagan, Illinois also consists of two phases. The initial phase of the Southern Access pipeline 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 at an estimated cost of approximately $160 million. The second phase of the Southern Access pipeline expansion will expand the pipeline to its full 1,200,000 Bpd potential with additional tankage requirements. The Line 61 expansion from 560,000 Bpd to 1,200,000 Bpd is now estimated to cost approximately $1.2 billion, which is a decrease of $90 million from the original estimated cost as a result of a more detailed engineering estimate. Both phases of the expansion require only the addition of pumping horsepower and crude oil tanks at new and existing sites with no pipeline construction. For the second phase of the Line 61 expansion, which remains subject to regulatory and other approvals, the pump station expansion is expected to be available for service in the third quarter of 2015, with the additional tankage is expected to be completed in early 2016.

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, will cost approximately $2.3 billion and will be undertaken on a cost-of-service basis. Furthermore, these projects are jointly funded by our General Partner and us, under the Mainline Expansion Joint Funding Agreement, which parallels the Eastern Access Joint Funding Agreement. On June 28, 2013, we exercised our option to decrease our economic interest and funding of the U.S. Mainline Expansions projects from 40% to 25%. Within one year of the in-service date, scheduled for 2016, we will have the option to increase its economic interest held at that time by up to 15 percentage points 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) partial 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 9B to provide additional delivery capacity within

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Ontario and Quebec; (5) expansions to add horsepower on existing lines on the Enbridge Mainline system from western Canada to the U.S. border which was completed in August 2014; and (6) modifications to existing terminal facilities on the Enbridge Mainline system, comprised of upgrading existing booster pumps, additional booster pumps and new tank line connections in order to accommodate additional light oil volumes and enhance operational flexibility. The outstanding projects have various targeted in-service dates through 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 projects in March 2014. On October 23, 2014, Enbridge responded to the NEB describing Enbridge's rigorous approach to risk management and isolation valve placement. Enbridge is currently awaiting response from the NEB to determine whether additional information is needed to satisfy the condition prior to applying for a Leave to Open allowing the operation of the project. As a result, Enbridge is unable to estimate the length of delay to the in-service date (previously expected in the fourth quarter of 2014). 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 United States Gulf Coast Projects and Southern Access Extension

One of our key strengths is our relationship with Enbridge. In 2011, Enbridge announced two major U.S. Gulf Coast market access pipeline projects, which, when completed, will pull more volume through our pipeline and may lead to further expansions of our Lakehead pipeline system. In addition, in 2012 Enbridge announced the Southern Access Extension, which will support the increasing supply of light oil from Canada and the Bakken into Patoka, Illinois.

Flanagan South Pipeline

Enbridge's Flanagan South Pipeline project will transport more volumes into Cushing, Oklahoma and twin its existing Spearhead pipeline, which starts at the hub in Flanagan, Illinois and delivers volumes into the Cushing hub. The 590-mile, 36-inch diameter pipeline has a design capacity of approximately 600,000 Bpd and was mechanically complete in September 2014 and line fill arrangements have begun and will continue throughout November 2014. However, in the initial years, it is not expected to operate to its full design capacity. In August 2013, the Sierra Club and National Wildlife Federation, the Plaintiff, filed a Complaint for Declaratory and Injunctive Relief, referred to as the Complaint, with the United States District Court for the District of Columbia, or the Court. The Complaint was filed against multiple federal agencies, or the Defendants, and included a request that the Court issue a preliminary injunction suspending previously granted federal permits and ordering Enbridge to discontinue construction of the project on the basis that the Defendants failed to comply with environmental review standards of the National Environmental Protection Act. In September 2013, Enbridge obtained intervener status and joined the Defendants in filing a response in opposition to the motion for preliminary injunction. The Plaintiff's request for preliminary injunction was denied by the Court in November 2013. A court hearing was held on February 21, 2014 concerning the merits of the Complaint against the Defendants. The Court ruled on August 18, 2014 dismissing all claims in favor of Enbridge and the federal agencies. The Plaintiffs filed an appeal to the U.S. Court of Appeals, D.C. Circuit.

Seaway Crude Pipeline

In 2011, Enbridge completed the acquisition of a 50% interest in the Seaway Crude Pipeline System, or Seaway. Seaway is a 670-mile pipeline that includes a 500-mile, 30-inch pipeline long-haul system that was reversed in 2012 to enable transportation of oil from Cushing, Oklahoma to Freeport, Texas, as well as a Texas City Terminal and Distribution System that serves refineries in the Houston and Texas City areas. Seaway also includes 6.8 million barrels of crude oil tankage on the Texas Gulf Coast and provided an initial capacity of 150,000 Bpd. Further pump station additions and modifications completed in January 2013 have increased the capacity to approximately 400,000 Bpd, depending upon the mix of light and heavy grades of crude oil.

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In March 2012, based on additional capacity commitments from shippers, plans were announced to proceed with an expansion of the Seaway Pipeline through construction of a second line to more than double its capacity to 850,000 Bpd. In July 2014, this second line, or Seaway Pipeline Twin, was mechanically complete with line fill expected to follow the completion of line fill for the Flanagan South Pipeline (discussed above). This 30-inch diameter pipeline follows the same route as the existing Seaway Pipeline. Also included in the scope of this second line, was a 65-mile, 36-inch diameter pipeline lateral from the Seaway Jones Creek facility to Enterprise Product Partners L.P.'s, or Enterprise Product's, ECHO crude oil terminal, or ECHO Terminal, in Houston, Texas that was completed in January 2014. Furthermore, the 100-mile pipeline from Enterprise Product's ECHO Terminal to the Port Arthur/Beaumont, Texas refining center to provide shippers access to the region's heavy oil refining capabilities was completed in August 2014. The new 100-mile pipeline offers incremental capacity of 750,000 Bpd.

Southern Access Extension

In December 2012, Enbridge announced that it would undertake the Southern Access Extension project, which will consist of the construction of a 165-mile, 24-inch diameter crude oil pipeline from Flanagan to Patoka, Illinois, as well as additional tankage and two new pump stations. The initial capacity of the new line is expected to be approximately 300,000 Bpd. On July 1, 2014, Enbridge entered into an agreement with Lincoln Pipeline LLC, or Lincoln, an affiliate of MPC, to, among other things, admit Lincoln as a partner and participate in the Southern Access Extension. Lincoln has purchased a 35% equity interest in the project and will make additional cash contributions in accordance with the Southern Access Extension's spend profile in proportion to its 35% interest. Subject to regulatory and other approvals, the project is expected to be placed into service in late 2015.

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 September 30,		For the nine month period ended September 30,	
	2014	2013	2014	2013
	(in millions)			
Operating revenues	$ 1,399.4	$ 1,387.9	$ 4,443.1	$ 4,054.4
Cost of natural gas	1,238.2	1,257.5	3,986.7	3,564.4
Operating and administrative	105.0	113.6	317.5	337.8
Depreciation and amortization	39.5	35.8	113.3	106.6
Operating expenses	1,382.7	1,406.9	4,417.5	4,008.8
Operating income (loss)	16.7	(19.0)	25.6	45.6
Other income	6.1	—	7.1	—
Net income (loss)	$ 22.8	$ (19.0)	$ 32.7	$ 45.6
Operating Statistics (MMBtu/d)				
East Texas	1,063,000	1,120,000	1,021,000	1,201,000
Anadarko	806,000	957,000	816,000	963,000
North Texas	304,000	314,000	292,000	326,000
Total	2,173,000	2,391,000	2,129,000	2,490,000
NGL Production (Bpd)	84,121	88,907	82,578	89,620

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Three month period ended September 30, 2014, compared with three month period ended September 30, 2013

The operating income of our Natural Gas business for the three month period ended September 30, 2014, increased $35.7 million, as compared with the same period in 2013. The most significant area affected was the Natural Gas segment gross margin, representing revenue less cost of natural gas, which increased $30.8 million for the three month period ended September 30, 2014, as compared with the same period in 2013.

Segment gross margin experienced an increase in non-cash, mark-to-market net gains of $50.2 million for the three month period ended September 30, 2014, compared to the same period in 2013, primarily related to increased gains in the three months ended September 30, 2014, on our NGL and condensate hedges and overall physical commodity gains from the non-qualifying physical NGL contracts. We are exposed to fluctuations in commodity prices in the near term on approximately 40% of the physical natural gas, NGLs and condensate we expect to receive as compensation for our services. As a result of this unhedged commodity price exposure, our segment gross margin generally increases when the prices of these commodities are rising and generally decreases when the prices are declining.

The following table depicts the effect that non-cash, mark-to-market net gains and losses had on the operating results of our Natural Gas segment for the three and nine month periods ended September 30, 2014, and 2013:

	For the three month period ended September 30,		For the nine month period ended September 30,	
	2014	2013	2014	2013
	(in millions)			
Hedge ineffectiveness	$ 0.9	$ (0.5)	$ 1.5	$ 1.8
Non-qualified hedges	16.8	(32.0)	10.0	(13.5)
Derivative fair value gains (losses)	$ 17.7	$ (32.5)	$ 11.5	$ (11.7)

Segment gross margin was negatively affected by the reduced production volumes by approximately $15.0 million for the three month period ended September 30, 2014, compared to the same period in 2013. The average daily volumes of our major systems for the three month period ended September 30, 2014, decreased by approximately 218,000 MMBtu/d, or 9%, when compared to the same period in 2013. The average NGL production for the three month period ended September 30, 2014, decreased 4,786 Bpd, or 5%, when compared to the same period in 2013. The decrease in natural gas and NGL volumes in the Anadarko region was primarily attributable to the loss of a major customer on our Anadarko system and reduced and delayed drilling activity by certain producers. The decrease in natural gas volumes in the East Texas region was primarily attributable to reduced dry gas drilling, and delayed drilling activity and well completions.

The natural gas and NGL production volumes have been improving quarter over quarter during the year and the outlook on our systems is expected to improve as we progress through the fourth quarter. We expect producer activity to increase in each of our asset regions with the exception of the Anadarko region. Additionally, drilling activity by natural gas producers in all regions is expected to target rich gas and oil prospects. This is notable in East Texas where existing processing capacity is full. Completion of the Beckville Cryogenic Processing Plant, which is expected to commence service in early 2015, is expected to alleviate this capacity constraint.

Segment gross margin increased by $2.5 million for the three months ended September 30, 2014, from contractual minimum volume commitments that will not be met before the contracts expire.

Segment gross margin increased $2.4 million for the three month period ended September 30, 2014, as compared with the same period in 2013 due to increased margins from pricing differentials.

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Our segment gross margin decreased $7.4 million for the three month period ended September 30, 2014, compared with the same period in 2013 due in part to lower storage volumes as a result of lower volumes received from our Gathering, Processing and Transportation segment.

The barrels that we produce under traditional keep-whole gas processing arrangements we refer to collectively as keep-whole earnings. Operating revenue less the cost of natural gas derived from keep-whole earnings for the three month period ended September 30, 2014, decreased $7.1 million from the same period in 2013, primarily due to lower ethane prices in the Anadarko region coupled with lower volumes of propane, butane, and natural gasoline.

Our segment gross margin decreased $4.1 million for the three month period ended September 30, 2014, compared with the same period in 2013 due to higher transportation and fractionation fees, freight costs, and product purchase costs, when compared to the same period in 2013.

Segment gross margin decreased $1.5 million for the three month period ended September 30, 2014, due to reduced pricing spreads between our Conway and Mont Belvieu market hubs when compared with the same period in 2013. On our Anadarko system, we purchase certain NGL components at Conway hub prices and then have the option to resell those same NGL components at Mont Belvieu hub prices.

Operating and administrative costs decreased $8.6 million for the three month period ended September 30, 2014, compared to the same period in 2013, due partly to lower volumes received from our Natural Gas segment and partly due to a strategic reduction of long hauls due to new geographically advantaged sales points.

Depreciation and amortization expense for our Natural Gas segment increased $3.7 million for the three month period ended September 30, 2014, compared with the same period of 2013, due to additional assets that were placed into service.

We recognized a $6.1 million equity income in “Other income (expense)” on our consolidated statement of income related to our investment in the Texas Express NGL system, which commenced startup operations during the fourth quarter of 2013.

Nine month period ended September 30, 2014, compared with nine month period ended September 30, 2013

The operating income of our Natural Gas business for the nine month period ended September 30, 2014, decreased $20.0 million, as compared with the same period in 2013. The most significant area affected was segment gross margin which decreased $33.6 million for the nine month period ended September 30, 2014, as compared with the same period in 2013.

Segment gross margin was affected by reduced production volumes which negatively affected segment gross margin by approximately $42.9 million for the nine month period ended September 30, 2014, compared to the same period in 2013. The average daily volumes of our major systems for the nine month period ended September 30, 2014, decreased by approximately 361,000 MMBtu/d, or 14% when compared to the same period in 2013. The average NGL production for the nine month period ended September 30, 2014, decreased by 7,042 Bpd, or 8%, when compared to the same period in 2013. The decrease in natural gas and NGL volumes in the Anadarko region was primarily attributable to the loss of a major customer on our Anadarko system and delayed drilling activity by certain producers. The decrease in natural gas volumes in the East Texas region was primarily attributable to reduced dry gas drilling, and delayed drilling activity and well completions.

Segment gross margin derived from keep-whole earnings for the nine month period ended September 30, 2014, decreased $19.0 million from the same period in 2013, due to a decrease in processing margins primarily driven by lower volumes in keep-whole barrels in the Oklahoma and North Texas regions.

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Our segment gross margin decreased $12.3 million for the nine month period ended September 30, 2014, compared with the same period in 2013 due in part to lower storage volumes as a result of lower volumes received from our Gathering, Processing and Transportation segment.

Segment gross margin decreased $3.7 million for the nine month period ended September 30, 2014, due to reduced pricing spreads between our Conway and Mont Belvieu market hubs when compared with the same period in 2013.

Segment gross margin decreased approximately $3.0 million for nine month period ended September 30, 2014, primarily due to the impact of sustained freezing temperatures in the first quarter 2014, which significantly disrupted producer well head production levels and our pipeline operations.

The decrease in segment gross margin was partially offset by increases in non-cash, mark-to-market net gains of $23.2 million for the nine month period ended September 30, 2014, compared to the same period in 2013 due to gains on our NGL, equity gas, and crude oil hedges, and overall physical commodity gains from the non-qualifying physical natural gas, NGL, and crude oil contracts.

Segment gross margin increased $8.9 million for the nine month period ended September 30, 2014, as compared with the same period in 2013 due to increased margins from pricing differentials. We benefited from the difference between market centers in the Mid-Continent supply areas and market area in the Midwest, which arose from higher than normal demand from winter weather in the Midwest.

The decrease in segment gross margin was partially offset by an increase of $6.9 million for the nine months ended September 30, 2014, due to contractual cumulative minimum volume commitments that will not be met before the contracts expire.

Operating and administrative costs of our Natural Gas segment decreased $20.3 million for the nine month period ended September 30, 2014, compared to the same period in 2013, due partly to lower volumes received from our Natural Gas segment and partly due to a strategic reduction of long hauls due to new geographically advantaged sales points.

Depreciation and amortization expense for our Natural Gas segment increased $6.7 million, for the nine month period ended September 30, 2014, compared with the same period of 2013, due to additional assets that were put in service.

We recognized $7.1 million in equity earnings in "Other income (expense)" on our consolidated statements of income related to our investment in the Texas Express NGL system, which commenced startup operations during the fourth quarter of 2013.

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. We have completed several expansion projects and are currently constructing one major expansion project that is designed to increase natural gas processing, NGL production, residue gas and NGL transportation capacity. The paragraph below summarizes our commercially secured project for the Natural Gas segment, which we expect to place into service in future periods.

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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. We expect our Beckville processing plant to be capable of processing approximately 150 million cubic feet per day, or 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. We estimate the cost of constructing the plant to be approximately $145.0 million and expect it to commence service in the first quarter of 2015.

The project is funded by us and MEP based on our proportionate ownership percentages in Midcoast Operating, which was 61% and 39%, respectively, before July 1, 2014, and 48.4% and 51.6%, respectively, after July 1, 2014.

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 September 30,		For the nine month period ended September 30,	
	2014	2013	2014	2013
	(in millions)			
Operating Results:				
Operating and administrative expenses	$ 3.8	$ 1.8	$ 6.9	$ 5.4
Operating loss	(3.8)	(1.8)	(6.9)	(5.4)
Interest expense, net	137.1	70.5	294.2	226.4
Allowance for equity used during construction	14.5	9.3	47.8	25.2
Other income (expense)	(4.3)	0.4	(4.9)	1.0
Income tax expense	2.1	1.5	6.1	17.5
Net loss	(132.8)	(64.1)	(264.3)	(223.1)
Noncontrolling interest	70.7	20.3	149.4	54.3
Series 1 preferred unit distributions	22.5	22.7	67.5	35.8
Accretion of discount on Series 1 preferred units	3.8	3.4	11.1	5.7
Net loss attributable to general and limited partners	$ (229.8)	$ (110.5)	$ (492.3)	$ (318.9)

Three month period ended September 30, 2014, compared with three month period ended September 30, 2013

The $68.7 million increase in our net loss for the three month period ended September 30, 2014, as compared to the same period in 2013 was primarily attributable to interest expense.

Our earnings and cash flows are exposed to the variability in longer term interest rates ahead of the anticipated fixed rate debt issuances. Forward starting interest rate swaps are used as cash flow hedges against the effect of future interest rate movements on earnings and cash flow. In order to mitigate the negative effect that increasing interest rates can have on our cash flows, we have purchased 10 year interest rate swaps with a total notional value of $2.35 billion as of September 30, 2014. 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

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relation to the hedged future debt issuances is recognized in income at the amendment date and each quarter end. For the three months ended September 30, 2014, interest expense increased due to recognition of unrealized losses for hedge ineffectiveness of approximately $62.2 million associated with interest rate hedges that were originally set to mature in 2014 and 2016.

Nine month period ended September 30, 2014, compared with nine month period ended September 30, 2013

The results for corporate activities for the nine month period ended September 30, 2014, compared to the same period in 2013, changed for the same reasons as noted in the three month analysis above in addition to the factors discussed below.

Income tax expense decreased $11.4 million for the nine month period ended September 30, 2014, compared to the same period in 2013, primarily due to a tax law that was passed in 2013 in the State of Texas, which resulted in a one-time increase to deferred income tax expense.

AEDC increased $22.6 million for the nine month period ended September 30, 2014, compared with the corresponding period in 2013, primarily related to construction on our Eastern Access projects.

Other Matters

Alberta Clipper Pipeline Joint Funding Arrangement

In July 2009, we entered into a joint funding arrangement to finance construction of the U.S. segment of the Alberta Clipper Pipeline with several of our affiliates and affiliates of Enbridge, including our General Partner. In connection with the joint funding arrangement, we allocated earnings derived from operating the Alberta Clipper Pipeline in the amount of $16.3 million and $13.4 million to our General Partner for its 66.67% share of the earnings of the Alberta Clipper Pipeline for the three month periods ended September 30, 2014 and 2013, respectively. We allocated earnings derived from operating the Alberta Clipper Pipeline in the amount of $38.0 million and $39.6 million to our General Partner for the nine month periods ended September 30, 2014, and September 30, 2013, respectively. We have presented the amounts we allocated to our General Partner for its share of the earnings of the Alberta Clipper Pipeline in “Net income attributable to noncontrolling interest” on our consolidated statements of income.

Alberta Clipper Drop Down Proposal

On September 17, 2014, we received a proposal from our General Partner pursuant to which our General Partner would drop down its 66.7% interest in the U.S. segment of the Alberta Clipper Pipeline to us for aggregate consideration of approximately $900 million. The proposed consideration would be cash of approximately $300 million, plus approximately $600 million of newly created Class E limited partner equity units to be issued to our General Partner by us. The Class E units would be entitled to the same distributions as the Class A common units and would be convertible into Class A common units on a one-for-one basis at our General Partners’ option. The Board of Directors of Enbridge Energy Management, the delegate of our General Partner, has appointed a special committee comprised of independent directors to review the proposal. Our acceptance of the proposal is subject to the review and favorable recommendation by the special committee and final approval by the Board of Directors. If approved, this transaction is targeted to close by the end of 2014.

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Joint Funding Arrangement for Eastern Access Projects

In May 2012, the OLP amended and restated its partnership agreement to establish an additional 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.

In connection with the partnership agreement, we allocated earnings from the Eastern Access Projects in the amount of $41.7 million and $6.6 million to our General Partner for its ownership of the EA interest, representing its 75% economic interest, for the three month periods ended September 30, 2014, and September 30, 2013, respectively. We allocated earnings derived from the Eastern Access Projects in the amount of $90.5 million and $14.4 million to our General Partner for the nine month periods ended September 30, 2014, and September 30, 2013, respectively. We have presented this amount we allocated to our General Partner in "Net income attributable to noncontrolling interest" on our consolidated statements of income.

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.

We allocated earnings from the Mainline Expansion Projects in the amount of $9.8 million and $0.3 million to our General Partner for its ownership of the ME interest, representing its 75% economic interest, for the three month periods ended September 30, 2014, and September 30, 2013, respectively. We allocated earnings from the Mainline Expansion Projects in the amount of $20.0 million and $0.3 million to our General Partner for its ownership of the ME interest for the nine month periods ended September 30, 2014, and September 30, 2013, respectively. We have presented the amount we allocated to our General Partner in "Net income attributable to noncontrolling interest" in our consolidated statements of income.

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. 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.

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As set forth in the following table, we had approximately $2.1 billion of liquidity available to us at September 30, 2014, 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	$ 230.4	$ 66.2
Total credit available under EEP's Credit Facilities	2,625.0	—
Total credit available under MEP's Credit Agreement	—	850.0
Less: Amounts outstanding under MEP's Credit Agreement	—	365.0
Principal amount of commercial paper issuances	1,100.0	—
Letters of credit outstanding	183.6	—
Total	$1,571.8	$551.2

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 September 30, 2014, we had a working capital deficit of approximately $0.8 billion and approximately $2.1 billion of liquidity to meet our ongoing operational, investing 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 Lines 6A and 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.

Midcoast Energy Partners, L.P.

On November 13, 2013, in connection with the closing of MEP's IPO, certain transactions, among others, occurred pursuant to which we effectively conveyed to MEP a 39% limited partner interest in Midcoast Operating.

On July 1, 2014, we sold a 12.6% limited partner interest in Midcoast Operating to MEP, for $350.0 million in cash, which brought our total ownership interest in Midcoast Operating from 61% to 48.4%. This transaction represents our first disposition of additional interests in Midcoast Operating since MEP's IPO on November 13, 2013. We intend to sell additional interests in our natural gas assets, held through Midcoast Operating, to MEP and use the proceeds from any such sale as a source of funding for us. However, we do not know when, or if, any additional interests will be offered for sale. At September 30, 2014, we owned 5.9% of the outstanding MEP Class A units, 100% of the outstanding MEP Subordinated Units, 100% of MEP's general partner and 48.4% of the limited partner interests in Midcoast Operating.

Under the Midcoast Operating Agreement, EEP and MEP each have the option to contribute its proportionate share of additional capital to Midcoast Operating if any additional capital contributions are necessary to fund capital expenditures or other growth projects. To the extent that MEP or EEP elect not to make any such capital contributions, the contributing party will be permitted to make additional capital contributions in exchange for additional interests in Midcoast Operating. EEP can elect not to participate in certain growth projects. We expect to participate proportionately in these natural gas capital projects, although there is no guarantee that we will do so.

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. See *Other Matters* above.

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 2014, we expect to spend approximately $1.6 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. We expect to receive funding of approximately $1.2 billion from our General Partner based on our joint funding arrangement for the Eastern Access Projects and Mainline Expansion Projects and $145.0 million from MPC based on joint funding arrangement on the Sandpiper Project. We recognized capital expenditures of $2.0 billion for the nine month period ending September 30, 2014, including $91.0 million on maintenance capital activities and $1.1 billion of expenditures that were financed by contributions from our General Partner and MPC via joint funding arrangements. In addition, we incurred $24.6 million in net contributions to fund our joint ventures. At September 30, 2014, we had approximately $1.3 billion in outstanding purchase commitments, before contributions from our joint funding arrangements with our General Partner, attributable to capital projects for the construction of assets that will be recorded as property, plant and equipment in the future.

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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.

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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 estimates of capital expenditures we expect to make for system enhancement and maintenance capital for the year ending December 31, 2014. Although we anticipate making these expenditures in 2014, 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. For the full year ending December 31, 2014, we anticipate the capital expenditures to approximate the following:

	Total Forecasted Expenditures (in millions)
Liquids Projects	
Eastern Access Projects	$ 775
U.S. Mainline Expansions	760
Sandpiper	390
Line 6B 75-mile Replacement Program	10
Line 3 Replacement	170
Liquids Integrity Program	325
Expansion Capital	255
Maintenance Capital Expenditures	70
	2,755
Less joint funding from:	
General Partner (1)	1,150
Third parties	145
Liquids Total	**$ 1,460**
Natural Gas Projects	
Beckville Cryogenic Processing Plant	$ 105
Expansion Capital	110
Maintenance Capital Expenditures	55
	270
Less joint funding from:	
MEP (2)	125
Natural Gas Total	**145**
TOTAL	**$ 1,605**

(1) No joint funding of the Line 3 Replacement is included in this line item as the joint funding agreement with Enbridge Inc. has not been completed.

(2) Joint funding is based upon six months of MEP at a 39% ownership of Midcoast Operating and six months of MEP at a 51.6% ownership of Midcoast Operating.

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.

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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. The capital spending components of our programs have increased over time as our pipeline systems age.

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 nine month period ended September 30, 2014, our cash flows were impacted by the approximate $117.4 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. Of the $1.21 billion in total cost accrued, we expect to pay a significant portion of the total remaining estimated cost of $219.4 million related to the Order received from the EPA during 2014.

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.

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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 September 30, 2014 for each of the indicated calendar years:

	Notional	2014	2015	2016	2017	2018	Total (4)
			(in millions)				
Swaps							
Natural gas (1)	78,671,325	$ 0.6	$ (0.6)	$(0.2)	$—	$—	$ (0.2)
NGL (2)	3,814,740	1.5	1.3	—	—	—	2.8
Crude Oil (2)	2,448,429	2.0	9.4	0.1	—	—	11.5
Options							
Natural gas—puts written (1)	5,119,000	(0.1)	(1.4)	—	—	—	(1.5)
Natural gas—puts purchased (1)	6,766,000	0.1	1.4	0.5	—	—	2.0
Natural gas—calls written (1)	2,924,500	—	(0.1)	(0.3)	—	—	(0.4)
Natural gas—calls purchased (1)	1,277,500	—	0.1	—			0.1
NGL—puts purchased (2)	2,824,700	0.9	5.5	6.5	—	—	12.9
NGL—calls purchased (2)	46,000	—	—	—	—	—	—
NGL—puts written (2)	32,200	(0.5)	—	—	—	—	(0.5)
NGL—calls written (2)	1,925,250	(0.1)	(1.7)	(5.6)	—	—	(7.4)
Crude Oil—puts purchased (2)	986,700	—	2.3	2.0	—	—	4.3
Crude Oil—calls written (2)	986,700	—	(2.1)	(2.2)	—	—	(4.3)
Forward contracts							
Natural gas (1)	230,964,144	0.6	0.7	0.3	0.1	—	1.7
NGL (2)	18,778,407	6.0	1.5	—	—	—	7.5
Crude Oil (2)	1,029,914	(1.6)	0.2	—	—	—	(1.4)
Power (3)	14,716	(0.1)	—	—	—	—	(0.1)
Totals		$ 9.3	$16.5	$ 1.1	$ 0.1	$—	$ 27.0

(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) Notional amounts for power are recorded in Megawatt hours, or MWh.
(4) Fair values exclude credit adjustments of approximately $0.2 million of losses at September 30, 2014.

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 September 30, 2014 for each of the indicated calendar years:

	Notional Amount	2014	2015	2016	2017	2018	Thereafter	Total (1)
				(in millions)				
Interest Rate Derivatives								
Interest Rate Swaps:								
Floating to Fixed	$2,480	$(1.5)	$ (8.2)	$ (4.2)	$ 0.8	$ (0.7)	$ 0.2	$ (13.6)
Pre-issuance hedges (2)	$2,350	—	(208.6)	(38.0)	(10.8)	12.4	—	(245.0)
		$(1.5)	$(216.8)	$(42.2)	$(10.0)	$11.7	$ 0.2	$(258.6)

(1) Fair values are presented in millions of dollars and exclude credit valuation adjustments of approximately $12.7 of gains at September 30, 2014.
(2) There was no cash collateral at September 30, 2014.

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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 nine month period ended September 30, 2014	2013	Variance 2014 vs. 2013 Increase (Decrease)
		(in millions)	
Total cash provided by (used in):			
Operating activities	$ 491.7	$ 942.5	$ (450.8)
Investing activities	(2,033.7)	(1,704.1)	(329.6)
Financing activities	1,673.8	557.3	1,116.5
Net increase (decrease) in cash and cash equivalents	131.8	(204.3)	336.1
Cash and cash equivalents at beginning of year	164.8	227.9	(63.1)
Cash and cash equivalents at end of period	$ 296.6	$ 23.6	$ 273.0

Operating Activities

Net cash provided by our operating activities decreased $450.8 million for the nine month period ended September 30, 2014 compared to the same period in 2013, primarily due to a decrease in our working capital accounts of $642.7 million. This decrease, due to our working capital accounts, was offset by a $268.4 million increase in net income offset by non-cash items of $82.6 million for the nine month period ended September 30, 2014 as compared to the same period in 2013.

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

	For the nine month period ended September 30, 2014	2013	Variance 2014 vs. 2013
		(in millions)	
Changes in operating assets and liabilities, net of acquisitions:			
Receivables, trade and other	$ 0.9	$ 66.2	$ (65.3)
Due from General Partner and affiliates	15.3	(4.9)	20.2
Accrued receivables	27.7	452.5	(424.8)
Inventory	(131.0)	(87.4)	(43.6)
Current and long-term other assets	(28.7)	(22.3)	(6.4)
Due to General Partner and affiliates	(23.4)	3.1	(26.5)
Accounts payable and other	(93.1)	28.0	(121.1)
Environmental liabilities	(116.7)	(79.8)	(36.9)
Accrued purchases	(28.6)	(77.0)	48.4
Interest payable	5.9	8.3	(2.4)
Property and other taxes payable	23.8	8.1	15.7
Net change in working capital accounts	$ (347.9)	$ 294.8	$(642.7)

The changes in our operating assets and liabilities, net of acquisitions as presented in our consolidated statements of cash flow for the nine month period ended September 30, 2014, compared to the same period in 2013, 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 trade receivables from December 31, 2012 to September 30, 2013 was primarily due to the sale of $79.8 million of trade receivables to a subsidiary of Enbridge pursuant to a purchase agreement, or the Receivables Agreement, that we entered into on June 28, 2013. This sale was

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partially offset by increased billings due to our Bakken projects entering service in March 2013 coupled with general timing differences in billing and receipt of payments;

- The change in accrued receivables from December 31, 2012 to September 30, 2013 was primarily the result of lower production of natural gas and NGLs from our facilities during the nine month period ended September 30, 2013. We sold $322.4 million of our accrued receivables outstanding as of December 31, 2012 to an Enbridge subsidiary under the Receivables Agreement. In addition, we had decreased volumes on our systems due to decreased natural gas drilling activity. For the nine month period ended September 30, 2014, our sales decreased even more than the nine month period ended September 30, 2013 due to continued reduced volumes; and
- The decline in accounts payable and other from December 31, 2013 to September 30, 2014 was primarily the result of book overdraft that was present at December 31, 2013 that was not present at September 30, 2014 coupled with decreased operating accruals related to our liquid pipelines. The primary driver of the increase in accounts payable and other from December 31, 2012 to September 30, 2013 was an increase in operating accruals associated with our Lakehead system partially offset by increased regulatory liability activities including amortization and over/under collections.

The above decrease was partially offset by an increase in net income of $268.4 million offset by a $82.6 million decrease in our non-cash items for the nine month period ended September 30, 2014 compared to the nine month period ended September 30, 2013. The decrease in non-cash items primarily consisted of the following:

- Decreased environmental costs of $139.6 million mainly attributed to $215.0 million in additional estimated costs recognized during 2013 related to the Line 6B crude oil release as a result of the Order accessed by the EPA in March 2013, while only $85.9 million in additional estimated costs were recognized in nine month period ended September 30, 2014;
- Increased derivative net losses of $45.9 million, compared to 2013, primarily as a result of fluctuations in commodity prices;
- Increased depreciation and amortization of $48.4 million due to projects placed in service in 2014;
- Increased allowance for equity used during construction, or AEDC, of $22.6 million attributable to the Eastern Access Projects and Mainline Expansion Projects partially offset by decreased AEDC due to the Line 6B (75-mile) Replacement project going into service early in 2014; and
- Decreased deferred income taxes for the nine month period ended September 30, 2014 of $12.0 million, primarily due to the new Texas Margin Tax law passed in the second quarter of 2013.

Investing Activities

Net cash used in our investing activities during the nine month period ended September 30, 2014 increased by $329.6 million, compared to the same period of 2013, primarily due to increased additions to property, plant and equipment, net of construction payables of $541.3 million in 2014 related to various enhancement projects, offset by the following:

- Decreased cash contributions of $146.4 million combined with decreased allowance for interest during construction associated with our joint venture project, Texas Express NGL system, as the project went into service at the end of 2013, coupled with $27.0 million in distributions in excess of cumulative earnings in 2014 from our joint venture investment in the Texas Express NGL system; and
- Decreased restricted cash balance of $33.4 million consisting of cash collections related to the receivables sold that have yet to be remitted to the Enbridge subsidiary in accordance with the Receivables Agreement.

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Financing Activities

Net cash provided by our financing activities increased $1,116.5 million for the nine month period ended September 30, 2014, compared to the same period in 2013, primarily due to the following:

- Increased net borrowings on our commercial paper of $1,534.7 million for the nine months ended September 30, 2014;
- Increased capital contributions from noncontrolling interest of $727.8 million in 2014 for ownership interests in the Mainline Expansion Projects, Eastern Access Projects and Sandpiper Project;
- Increased net proceeds from issuance of MEP senior notes totaling $398.1 million in 2014 compared to no activity in 2013;
- Decreased repayments on long-term debt of $200.0 million for 2014, due to us repaying in full our 4.750% Senior Notes due in 2013 compared to no payments on our Senior Notes in 2014; and
- Increased net borrowings on the MEP Credit Agreement of $30.0 million in 2014, compared to no activity in 2013.

Offsetting the increases above were the following:

- Decreased net proceeds in 2014 of $1,200.0 million due to no preferred unit issuances in 2014 while we had a preferred unit issuance in 2013;
- Decreased net proceeds from unit issuances, including our General Partner's contributions of $519.3 million from 2013 while we had no issuances in 2014; and
- Increased distributions to our limited partners of $13.6 million and distributions to noncontrolling interest of $41.2 million.

SUBSEQUENT EVENTS

Credit Facility Agreement Amendments

On October 6, 2014, we amended the Credit Facility to extend the maturity date from September 26, 2018 to September 26, 2019; however, $175.0 million of commitments will expire on the original maturity date of September 26, 2018.

Distribution to Partners

On October 31, 2014, the board of directors of Enbridge Management declared a distribution payable to our partners on November 14, 2014. The distribution will be paid to unitholders of record as of November 7, 2014 of our available cash of $221.8 million at September 30, 2014, or $0.5550 per limited partner unit. Of this distribution, $183.7 million will be paid in cash, $37.3 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 AC Interests

On October 31, 2014, 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 AC interests, declared a distribution payable to the holders of the Series AC general and limited partner interests. The OLP will pay $20.3 million to the noncontrolling interest in the Series AC, while $10.1 million will be paid to us.

Distribution to Series EA Interests

On October 31, 2014, 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,

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declared a distribution payable to the holders of the Series EA general and limited partner interests. The OLP will pay $43.7 million to the noncontrolling interest in the Series EA, while $14.6 million will be paid to us.

Distribution to Series ME Interests

On October 31, 2014, 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 $1.9 million to the noncontrolling interest in the Series ME, while $0.6 million will be paid to us.

Distribution from MEP

On October 30, 2014, 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 their partners on November 14, 2014. The distribution will be paid to unitholders of record as of November 7, 2014, of MEP's available cash of $15.6 million at September 30, 2014, or $0.3375 per limited partner unit. MEP will pay $7.2 million to their public Class A common unitholders, while $8.4 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 October 30, 2014, the general partner of Midcoast Operating, acting in its capacity as the general partner of Midcoast Operating, declared a cash distribution by Midcoast Operating payable to its partners of record as of November 7, 2014. Midcoast Operating will pay $12.6 million to us and $13.5 million to MEP.

REGULATORY MATTERS

FERC Transportation Tariffs

Lakehead System

On June 27, 2014, Lakehead filed for an increase effective August 1, 2014 to its system rates. This rate filing was in part an index filing in accordance with 18 CFR 342.3 and in part a compliance filing with certain settlement agreements, which are not subject to FERC indexing. This filing included the increase in rates in compliance with the indexed rate ceilings allowed by the FERC which incorporates the multiplier of 1.038858, which was issued by the FERC on May 14, 2014, in Docket No. RM93-11-000. This filing also reflected an annual rate adjustment for the Facilities Surcharge Mechanism, or FSM, components of the Lakehead system. The FSM allows Lakehead to recover costs associated with particular shipper-approved projects through an incremental surcharge layered on top of the base rates. The FSM surcharge rates reflect our projected costs for these shipper-approved projects for 2014 and true-ups for the difference between estimated and actual costs for the prior year. Historically, the Lakehead system annual tariff rate adjustment for the FSM component of rates with an effective date of April 1 and the index rate filing with an effective date of July 1; however, the filings were delayed due to the then ongoing negotiations with the CAPP concerning certain components of the tariff rate structure. This negotiation eliminated the System Expansion Project II, or SEPII, surcharge and added recovery of the associated SEP II rate base to the FSM component of Lakehead rates. The rate base consisted of the costs for Line 14 and certain legacy integrity costs which were incurred to maintain the integrity and safety of the pipeline. The rates also include recovery of costs related to additional FSM projects, the Eastern Access Phase 2 Mainline Expansion, and the 2014 Mainline Expansions.

This tariff filing increased the transportation rate for heavy crude oil movements from the Canadian border to the Chicago, Illinois area by approximately $0.32 per barrel, to approximately $2.49 per barrel. The surcharge is applicable to each barrel of crude oil that is placed on our system beginning on 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.

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Effective April 1, 2013, we filed our Lakehead system annual tariff rate adjustment with the FERC to reflect our projected costs and throughput for 2013 and true-ups for the difference between estimated and actual costs and throughput data for the prior year. This tariff rate adjustment filing also included the recovery of costs related to the Flanagan Tank Replacement Project and the Eastern Access Phase 1 Mainline Expansion Project. The Lakehead system utilized the SEPII and the FSM, which are components of our Lakehead system's overall rate structure and allows for the recovery of costs for enhancements or modifications to our Lakehead system.

This tariff filing increased the transportation rate for heavy crude oil movements from the Canadian border to the Chicago, Illinois area by approximately $0.28 per barrel, to approximately $2.13 per barrel. The surcharge is applicable to each barrel of crude oil that is placed on our system beginning on 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.

*North Dakota and Ozark System*s

North Dakota FERC tariffs Nos. 72.29 and 3.0.0, with effective dates of January 24, 2014, were filed to implement the name change of the North Dakota System from Enbridge Pipelines (North Dakota) LLC to North Dakota Pipeline Company, LLC.

Effective April 1, 2014, 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 trued up each year to actual costs and volumes and are not subject to the FERC indexing methodology. The filing increased transportation rates for all crude oil movements on our North Dakota system with a destination of Clearbrook, Minnesota by an average of approximately $0.05 per barrel, to an average of approximately $2.21 per barrel.

Effective May 8, 2014, FERC tariff No. 3.4.0 cancelled transportation rates on the North Dakota System from Flat Lake, Montana, as the pipeline is no longer providing service from that receipt point.

On May 30, 2014, we filed FERC tariffs with effective dates of July 1, 2014 for our North Dakota and Ozark systems. We increased the rates in compliance with the indexed rate ceilings allowed by the FERC which incorporates the multiplier of 1.038858, which was issued by the FERC on May 14, 2014, in Docket No. RM93-11-000.

Effective April 1, 2013 for the North Dakota system 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. As previously mentioned, these surcharges are cost-of-service based surcharges that are trued up each year to actual costs and volumes and are not subject to the FERC indexing methodology. This filing increased the average transportation rate for crude oil movements on our North Dakota System by $0.55 per barrel, to an average of approximately $2.06 per barrel.

Effective July 1, 2013, we filed FERC tariffs for our North Dakota and Ozark systems. We increased the rates in compliance with the indexed rate ceilings allowed by FERC which incorporates the multiplier of 1.045923, which was issued by FERC on May 15, 2013, in Docket No. RM93-11-000.

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, 2013, 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

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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 September 30, 2014.

Date of Maturity & Contract Type	Accounting Treatment	Notional	Average Fixed Rate [1]	Fair Value [2] at September 30, 2014	Fair Value [2] at December 31, 2013
			(dollars in millions)		
Contracts maturing in 2015					
Interest Rate Swaps—Pay Fixed	Cash Flow Hedge	$ 510	1.53%	$ (1.9)	$ (6.8)
Contracts maturing in 2016					
Interest Rate Swaps—Pay Fixed	Cash Flow Hedge	$ 90	0.55%	$ —	—
Contracts maturing in 2017					
Interest Rate Swaps—Pay Fixed	Cash Flow Hedge	$ 450	2.21%	$ (12.2)	$ (13.8)
Contracts maturing in 2018					
Interest Rate Swaps—Pay Fixed	Cash Flow Hedge	$ 810	2.24%	$ 1.4	$ 3.3
Contracts maturing in 2019					
Interest Rate Swaps—Pay Fixed	Cash Flow Hedge	$ 620	2.96%	$ (1.0)	$ —
Contracts settling prior to maturity					
2014—Pre-issuance Hedges [3]	Cash Flow Hedge	$ —	0.00%	$ —	$ (132.7)
2015—Pre-issuance Hedges	Cash Flow Hedge	$1,000	5.48%	$ (208.5)	—
2016—Pre-issuance Hedges	Cash Flow Hedge	$ 500	4.21%	$ (38.0)	$ 60.8
2017—Pre-issuance Hedges	Cash Flow Hedge	$ 500	3.69%	$ (10.8)	—
2018—Pre-issuance Hedges	Cash Flow Hedge	$ 350	3.08%	$ 12.4	—

(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 September 30, 2014 and December 31, 2013, 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 $12.7 million of gains at September 30, 2014 and $7.1 million of losses at December 31, 2013.

(3) Includes $16.7 million of cash collateral at December 31, 2013.

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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 September 30, 2014 and December 31, 2013.

	At September 30, 2014						At December 31, 2013	
			Wtd. Average Price (2)		Fair Value (3)		Fair Value (3)	
	Commodity	Notional (1)	Receive	Pay	Asset	Liability	Asset	Liability
					(in millions)			
Portion of contracts maturing in 2014								
Swaps								
Receive variable/pay fixed	Natural Gas	668,692	$ 4.00	$ 3.91	$ 0.1	$ —	$ —	$ —
	NGL	623,000	$ 56.02	$56.64	$ 0.3	$ (0.7)	$ 0.6	$ (0.4)
	Crude Oil	95,000	$ 89.87	$92.56	$—	$ (0.3)	$ —	$ —
Receive fixed/pay variable	Natural Gas	2,380,100	$ 4.26	$ 4.09	$ 0.5	$ (0.1)	$ 0.1	$ (1.0)
	NGL	2,021,140	$ 51.91	$50.97	$ 3.7	$ (1.8)	$ 4.8	$ (12.7)
	Crude Oil	457,764	$ 95.26	$90.14	$ 2.7	$ (0.4)	$ 3.4	$ (5.4)
Receive variable/pay variable	Natural Gas	19,562,500	$ 4.03	$ 4.02	$ 0.6	$ (0.5)	$ 0.6	$ (0.1)
Physical Contracts								
Receive variable/pay fixed	Natural Gas	313,224	$ 3.89	$ 1.23	$ 0.8	$ —	$ —	$ —
	NGL	550,000	$ 42.40	$43.88	$—	$ (0.8)	$ 0.9	$ (0.9)
	Crude Oil	45,000	$ 90.85	$93.90	$—	$ (0.1)	$ —	$ —
Receive fixed/pay variable	Natural Gas	185,506	$ 4.03	$ 3.97	$—	$ —	$ —	$ —
	NGL	3,504,872	$ 39.20	$37.85	$ 5.1	$ (0.4)	$ 0.4	$ (2.6)
	Crude Oil	75,000	$ 93.08	$90.62	$ 0.2	$ —	$ —	$ (0.4)
Pay fixed	Power (4)	14,716	$ 37.84	$46.59	$—	$ (0.1)	$ —	$ (0.7)
Receive variable/pay variable	Natural Gas	72,613,470	$ 4.02	$ 4.02	$ 0.9	$ (1.1)	$ 0.9	$ (0.4)
	NGL	10,947,422	$ 42.80	$42.61	$ 2.7	$ (0.6)	$ 5.8	$ (3.7)
	Crude Oil	758,914	$ 88.26	$90.52	$ 0.8	$ (2.5)	$ 1.1	$ (1.2)
Portion of contracts maturing in 2015								
Swaps								
Receive variable/pay fixed	Natural Gas	316,837	$ 3.91	$ 3.93	$—	$ —	$ —	$ —
	NGL	145,850	$ 72.56	$78.20	$—	$ (0.8)	$ —	$ —
	Crude Oil	456,000	$ 87.81	$92.94	$—	$ (2.3)	$ —	$ —
Receive fixed/pay variable	Natural Gas	809,761	$ 4.56	$ 4.21	$ 0.3	$ —	$ —	$ —
	NGL	1,024,750	$ 54.42	$52.36	$ 3.1	$ (1.0)	$ 1.5	$ (1.1)
	Crude Oil	1,303,165	$ 96.75	$87.78	$11.7	$ —	$ 8.3	$ —
Receive variable/pay variable	Natural Gas	42,725,000	$ 3.92	$ 3.94	$ 0.8	$ (1.7)	$ 0.1	$ —
Physical Contracts								
Receive variable/pay fixed	NGL	95,000	$ 46.73	$48.37	$—	$ (0.2)	$ —	$ —
Receive fixed/pay variable	NGL	586,394	$ 49.38	$47.79	$ 1.0	$ —	$ —	$ —
Receive variable/pay variable	Natural Gas	108,991,322	$ 4.05	$ 4.05	$ 1.4	$ (0.7)	$ 0.5	$ (0.1)
	NGL	3,094,719	$ 61.40	$61.19	$ 1.2	$ (0.5)	$ —	$ —
	Crude Oil	151,000	$ 90.30	$88.89	$ 0.2	$ —	$ —	$ —
Portion of contracts maturing in 2016								
Swaps								
Receive variable/pay fixed	Natural Gas	181,435	$ 3.78	$ 3.85	$—	$ —	$ —	$ —
	Crude Oil	68,250	$ 86.36	$90.00	$—	$ (0.2)	$ —	$ —
Receive fixed/pay variable	Crude Oil	68,250	$ 90.89	$86.36	$ 0.3	$ —	$ 0.7	$ —
Receive variable/pay variable	Natural Gas	12,027,000	$ 3.96	$ 3.98	$ 0.1	$ (0.3)	$ —	$ —
Physical Contracts								
Receive variable/pay variable	Natural Gas	34,560,879	$ 4.06	$ 4.05	$ 0.7	$ (0.4)	$ 0.1	$ —
Portion of contracts maturing in 2017								
Physical Contracts								
Receive variable/pay variable	Natural Gas	14,299,743	$ 4.27	$ 4.26	$ 0.2	$ (0.1)	$ —	$ —

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

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

(3) The fair value is determined based on quoted market prices at September 30, 2014 and December 31, 2013, 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 $0.1 million of gains at September 30, 2014 and December 31, 2013, respectively.

(4) For physical power, the receive price shown represents the index price used for valuation purposes.

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The following table provides summarized information about the fair values of expected cash flows of our outstanding commodity options at September 30, 2014 and December 31, 2013.

	At September 30, 2014						At December 31, 2013	
					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 2014								
Puts (purchased)	Natural Gas	1,104,000	$ 3.90	$ 4.10	$ 0.1	$ —	$ 0.7	$ —
	NGL	193,200	$54.79	$52.43	$ 0.9	$ —	$ 2.9	$ —
Calls (written)	NGL	115,000	$60.92	$54.59	$—	$ (0.1)	$ —	$ (1.0)
Puts (written)	Natural Gas	1,104,000	$ 3.90	$ 4.10	$—	$ (0.1)	$ —	$ (0.5)
	NGL	32,200	$66.36	$51.70	$—	$ (0.5)	$ —	$ —
Calls (purchased)	NGL	46,000	$50.40	$43.84	$—	$ —	$ —	$ —
Portion of option contracts maturing in 2015								
Puts (purchased)	Natural Gas	4,015,000	$ 3.90	$ 4.00	$ 1.4	$ —	$ 1.7	$ —
	NGL	1,350,500	$48.75	$50.62	$ 5.5	$ —	$ 6.0	$ —
	Crude Oil	547,500	$85.42	$87.76	$ 2.3	$ —	$ 1.8	$ —
Calls (written)	Natural Gas	1,277,500	$ 5.05	$ 4.00	$—	$ (0.1)	$ —	$ (0.3)
	NGL	529,250	$55.18	$50.29	$—	$ (1.7)	$ —	$ (1.0)
	Crude Oil	547,500	$91.75	$87.76	$—	$ (2.1)	$ —	$ (1.9)
Puts (written)	Natural Gas	4,015,000	$ 3.90	$ 4.00	$—	$ (1.4)	$ —	$ —
Calls (purchased)	Natural Gas	1,277,500	$ 5.05	$ 4.00	$ 0.1	$ —	$ —	$ —
Portion of option contracts maturing in 2016								
Puts (purchased)	Natural Gas	1,647,000	$ 3.75	$ 4.08	$ 0.5	$ —	$ —	$ —
	NGL	1,281,000	$41.82	$44.06	$ 6.5	$ —	$ —	$ —
	Crude Oil	439,200	$80.00	$85.93	$ 2.0	$ —	$ —	$ —
Calls (written)	Natural Gas	1,647,000	$ 4.98	$ 4.08	$—	$ (0.3)	$ —	$ —
	NGL	1,281,000	$48.59	$44.06	$—	$ (5.6)	$ —	$ —
	Crude Oil	439,200	$92.25	$85.93	$—	$ (2.2)	$ —	$ —

(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 September 30, 2014 and December 31, 2013, 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.

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.

	September 30, 2014	December 31, 2013
	(in millions)	
Counterparty Credit Quality [1]		
AAA	$ 0.3	$ 0.3
AA	(91.0)	(49.7)
A [2]	(134.0)	(40.1)
Lower than A	5.6	0.8
	$ (219.1)	$ (88.7)

(1) As determined by nationally-recognized statistical ratings organizations.
(2) Includes $16.7 million of cash collateral at December 31, 2013.

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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 September 30, 2014. 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 September 30, 2014.

PART II—OTHER INFORMATION

Item 1. Legal Proceedings

Refer to Part I, Item 1. *Financial Statements*, "Note 9. *Commitments and Contingencies*," which is incorporated herein by reference.

Item 1A. Risk Factors

None.

Item 6. Exhibits

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

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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: November 3, 2014

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

Date: November 3, 2014

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

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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	Subordination Agreement, dated as of September 30, 2014, by and among Midcoast Energy Partners, L.P., other obligors from time to time party thereto, Enbridge Energy Partners, L.P., and certain of its subsidiaries and affiliates from time to time party thereto in favor of the holders from time to time of the Notes (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K, filed on October 6, 2014).
10.2	Amended and Restated Subordination Agreement Subordination Agreement, dated as of September 30, 2014, by and among Midcoast Energy Partners, L.P., Midcoast Operating, L.P., the other credit parties from time to time party thereto and Enbridge Energy Partners, L.P. in favor of Bank of America, N.A., as Administrative Agent (incorporated by reference to Exhibit 10.2 to our Current Report on Form 8-K, filed on October 6, 2014).
10.3	Extension Agreement and Fifth Amendment to Credit Agreement, dated as of October 6, 2014, by and among Enbridge Energy Partners, L.P., the lender parties thereto and Bank of America, N.A., as administrative agent (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K, filed on October 10, 2014).
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: November 3, 2014

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: November 3, 2014

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 September 30, 2014 (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: November 3, 2014

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 September 30, 2014 (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: November 3, 2014

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)