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

FORM 10-Q

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

For the quarterly period ended March 31, 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 May 1, 2014.

ENBRIDGE ENERGY PARTNERS, L.P.

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In this report, unless the context requires otherwise, references to "we," "us," "our" 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 or the supply of, forecast data for, and price trends related to crude oil, liquid petroleum, natural gas and 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).

PART I—FINANCIAL INFORMATION

Item 1. Financial Statements

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

	For the three month period ended March 31,	
	2014	2013
	(unaudited; in millions, except per unit amounts)	
Operating revenue (Note 11)	$2,004.5	$1,628.3
Operating revenue—affiliate	75.1	64.7
	2,079.6	1,693.0
Operating expenses:		
Cost of natural gas (Notes 5 and 11)	1,458.5	1,153.3
Cost of natural gas—affiliate	30.2	38.1
Environmental costs, net of recoveries (Note 10)	5.0	178.5
Operating and administrative	96.6	82.0
Operating and administrative—affiliate	120.4	112.9
Power (Note 11)	50.4	33.6
Depreciation and amortization (Note 6)	103.8	92.2
	1,864.9	1,690.6
Operating income	214.7	2.4
Interest expense, net (Notes 7 and 11)	76.9	76.4
Allowance for equity used during construction (Note 14)	20.7	7.8
Other income (expense)	(0.8)	0.3
Income (loss) before income tax expense	157.7	(65.9)
Income tax expense (Note 12)	2.0	1.8
Net income (loss)	155.7	(67.7)
Less: Net income attributable to:		
Noncontrolling interest (Note 9)	36.3	15.6
Series 1 preferred unit distributions (Note 8)	22.5	—
Accretion of discount on Series 1 preferred units (Note 8)	3.6	—
Net income (loss) attributable to general and limited partner ownership interest in Enbridge Energy Partners, L.P.	$ 93.3	$ (83.3)
Net income (loss) allocable to limited partner interests	$ 58.9	$ (112.9)
Net income (loss) per limited partner unit (basic) (Note 3)	$ 0.18	$ (0.36)
Weighted average limited partner units outstanding (basic)	326.4	307.2
Net income (loss) per limited partner unit (diluted) (Note 3)	$ 0.18	$ (0.36)
Weighted average limited partner units outstanding (diluted)	326.4	307.2

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

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

	For the three month period ended March 31,	
	2014	2013
	(unaudited; in millions)	
Net income (loss)	$155.7	$(67.7)
Other comprehensive income (loss), net of tax expense (benefit) of $0.0 million in March 31, 2014 and 2013, respectively (Note 11)	(70.0)	29.7
Comprehensive income (loss)	85.7	(38.0)
Less: Comprehensive income attributable to:		
Noncontrolling interest (Note 9)	36.3	15.6
Series 1 preferred unit distributions (Note 8)	22.5	—
Accretion of discount on Series 1 preferred units (Note 8)	3.6	—
Comprehensive income (loss) attributable to general and limited partner ownership interests in Enbridge Energy Partners, L.P.	$ 23.3	$(53.6)

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

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

	For the three month period ended March 31, 2014	2013
	(unaudited; in millions)	
Cash provided by operating activities:		
Net income (loss)	$ 155.7	$ (67.7)
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization (Note 6)	103.8	92.2
Derivative fair value net losses (Note 11)	3.3	4.2
Inventory market price adjustments (Note 5)	1.5	0.8
Environmental costs, net of recoveries (Note 10)	4.4	173.5
Distributions from investment in joint venture (Note 9)	1.6	—
Equity loss in investment in joint venture (Note 9)	1.3	—
Allowance for equity used during construction (Note 14)	(20.7)	(7.8)
Other (Note 15)	2.7	3.6
Changes in operating assets and liabilities, net of acquisitions:		
Receivables, trade and other	(14.5)	(23.3)
Due from General Partner and affiliates	4.5	(5.4)
Accrued receivables	74.6	142.0
Inventory (Note 5)	26.9	(14.6)
Current and long-term other assets (Note 11)	(4.8)	(8.0)
Due to General Partner and affiliates	(11.0)	29.3
Accounts payable and other (Notes 4 and 11)	(85.0)	(67.6)
Environmental liabilities (Note 10)	(42.0)	(13.6)
Accrued purchases	(6.3)	(40.7)
Interest payable	5.7	6.9
Property and other taxes payable	9.1	2.1
Net cash provided by operating activities	210.8	205.9
Cash used in investing activities:		
Additions to property, plant and equipment (Note 6)	(612.8)	(404.9)
Asset acquisitions	—	(0.9)
Changes in restricted cash (Note 9)	52.6	—
Proceeds from sale of net assets	—	5.0
Investment in joint venture (Note 9)	(7.3)	(36.8)
Other	(0.3)	(0.3)
Net cash used in investing activities	(567.8)	(437.9)
Cash provided by financing activities:		
Net proceeds from unit issuances (Note 8)	—	278.7
Distributions to partners (Note 8)	(178.4)	(176.1)
Repayments to General Partner (Note 9)	(6.0)	(6.0)
Net repayments under credit facility (Note 7)	(85.0)	—
Net commercial paper borrowings (Note 7)	390.1	140.0
Contributions from noncontrolling interest (Note 9)	289.7	22.8
Distributions to noncontrolling interest (Note 9)	(16.3)	(13.8)
Net cash provided by financing activities	394.1	245.6
Net increase in cash and cash equivalents	37.1	13.6
Cash and cash equivalents at beginning of year	164.8	227.9
Cash and cash equivalents at end of period	$ 201.9	$ 241.5

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

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

	March 31, 2014	December 31, 2013
	(unaudited; in millions)	
ASSETS		
Current assets:		
Cash and cash equivalents (Note 4)	$ 201.9	$ 164.8
Restricted cash (Note 9)	16.8	69.4
Receivables, trade and other, net of allowance for doubtful accounts of $0.5 million in 2014 and 2013 (Note 10)	46.9	49.4
Due from General Partner and affiliates	36.6	40.5
Accrued receivables	152.6	210.2
Inventory (Note 5)	67.9	94.9
Other current assets (Note 11)	52.3	47.6
	575.0	676.8
Property, plant and equipment, net (Note 6)	13,749.8	13,176.8
Goodwill	246.7	246.7
Intangibles, net	258.9	263.2
Other assets, net (Note 11)	522.5	538.0
	$15,352.9	$14,901.5
LIABILITIES AND PARTNERS' CAPITAL		
Current liabilities:		
Due to General Partner and affiliates	$ 103.9	$ 121.4
Accounts payable and other (Notes 4, 6, 11 and 14)	792.6	822.0
Environmental liabilities (Note 10)	196.2	233.7
Accrued purchases	460.7	465.6
Interest payable	73.7	68.0
Property and other taxes payable (Notes 6 and 12)	79.5	70.7
Note payable to General Partner (Note 9)	12.0	12.0
Current maturities of long-term debt (Note 7)	200.0	200.0
	1,918.6	1,993.4
Long-term debt (Note 7)	5,082.6	4,777.4
Loans from General Partner and affiliate (Note 9)	300.0	306.0
Due to General Partner and affiliates	80.8	58.2
Deferred income tax liability (Notes 6 and 12)	18.0	17.4
Other long-term liabilities (Notes 10 and 11)	97.3	51.7
Total liabilities	7,497.3	7,204.1
Commitments and contingencies (Note 10)		
Partners' capital: (Notes 8 and 9)		
Series 1 preferred units (48,000,000 at March 31, 2014 and December 31, 2013)	1,116.6	1,160.7
Class A common units (254,208,428 at March 31, 2014 and December 31, 2013)	2,923.8	2,979.0
Class B common units (7,825,500 at March 31, 2014 and December 31, 2013)	63.7	65.3
i-units (64,984,750 and 63,743,099 at March 31, 2014 and December 31, 2013, respectively)	1,311.2	1,291.9
General Partner	301.6	301.5
Accumulated other comprehensive income (loss) (Note 11)	(146.6)	(76.6)
Total Enbridge Energy Partners, L.P. partners' capital	5,570.3	5,721.8
Noncontrolling interest (Note 9)	2,285.3	1,975.6
Total partners' capital	7,855.6	7,697.4
	$15,352.9	$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

The accompanying unaudited interim consolidated financial statements have been prepared 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, they do not include all the information and footnotes required by GAAP for complete consolidated financial statements. In the opinion of management, they contain all adjustments, consisting only of normal recurring adjustments, which management considers necessary to present fairly our financial position as of March 31, 2014, our results of operations for the three month periods ended March 31, 2014 and 2013, and our cash flows for the three month periods ended March 31, 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 three month period ended March 31, 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, the Partnership changed its 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 Enbridge Energy Partners, L.P., or EEP, resulting from Midcoast Energy Partner, L.P.’s, or, MEP’s, initial public offering, or IPO, of its Class A common units representing limited partnership interests 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.

Additionally, we made a reclassification of $7.8 million for equity used during construction from “Other income (expense)” to “Allowance for equity used during construction” in our consolidated statements of income for the three month period ended March 31, 2013.

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

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Obligations Resulting from Joint and Several Liability Arrangements

Effective January 1, 2014, we retrospectively adopted Financial Accounting Standards Board, or FASB, Accounting Standards Update No. 2013-04, which provides measurement and disclosure guidance for obligations with fixed amounts at a reporting date resulting from joint and several liability arrangements. There was no material impact to the consolidated financial statements for the current or prior periods presented as a result of adopting this update.

3. NET INCOME PER LIMITED PARTNER UNIT

We allocate our net income among our Series 1 Preferred Units, or Preferred Units, Enbridge Energy Company, Inc., our General Partner, and our limited partners using first preferred unit distributions and then the two-class method in accordance with applicable authoritative accounting guidance. Under the two-class method, we allocate our net income, after noncontrolling interest and preferred unit distributions, including any incentive distribution rights embedded in the general partner interest, 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, after Preferred Unit allocations, based on their sharing of losses of 2% and 98%, respectively, as set forth in our partnership agreement, 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 %

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

	For the three month period ended March 31,	
	2014	2013
	(in millions, except per unit amounts)	
Net income (loss)	$ 155.7	$ (67.7)
Less Net income attributable to:		
Noncontrolling interest	(36.3)	(15.6)
Series 1 preferred unit distributions	(22.5)	—
Accretion of discount on Series 1 preferred units	(3.6)	—
Net income attributable to general and limited partner interests in Enbridge Energy Partners, L.P.	93.3	(83.3)
Less distributions:		
Incentive distributions to our General Partner	(33.2)	(31.9)
Distributed earnings allocated to our General Partner	(3.6)	(3.5)
Total distributed earnings to our General Partner	(36.8)	(35.4)
Total distributed earnings to our limited partners	(177.7)	(170.8)
Total distributed earnings	(214.5)	(206.2)
Overdistributed earnings	$(121.2)	$(289.5)
Weighted average limited partner units outstanding	326.4	307.2
Basic and diluted earnings per unit:		
Distributed earnings per limited partner unit (1)	$ 0.54	$ 0.56
Overdistributed earnings per limited partner unit (2)	(0.36)	(0.92)
Net income (loss) per limited partner unit (basic and diluted) (3)	$ 0.18	$ (0.36)

(1) Represents the total distributed earnings to limited partners divided by the weighted average number of limited partner interests outstanding for the period.

(2) Represents the limited partners' share (98%) of distributions in excess of earnings divided by the weighted average number of limited partner interests outstanding for the period and overdistributed earnings allocated to the limited partners based on the distribution waterfall that is outlined in our partnership agreement.

(3) For the three month period ended March 31, 2014, 43,201,310 anti-dilutive Preferred Units were excluded from the if-converted method of calculating diluted earnings per unit.

4. CASH AND CASH EQUIVALENTS

We extinguish liabilities when a creditor has relieved us of our obligation, which occurs when our financial institution honors a check that the creditor has presented for payment. Accordingly, obligations for which we have made payments that have not yet been presented to the financial institution totaling approximately $14.0 million at March 31, 2014, and $24.0 million at December 31, 2013, are included in "Accounts payable and other" on our consolidated statements of financial position.

5. INVENTORY

Our inventory is comprised of the following:

	March 31, 2014	December 31, 2013
	(in millions)	
Materials and supplies	$ 2.1	$ 2.1
Crude oil inventory	17.2	18.0
Natural gas and NGL inventory	48.6	74.8
	$67.9	$94.9

The “Cost of natural gas” on our consolidated statements of income includes charges totaling $1.5 million and $0.8 million, for the three month periods ended March 31, 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.

6. PROPERTY, PLANT AND EQUIPMENT

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

	March 31, 2014	December 31, 2013
	(in millions)	
Land	$ 43.2	$ 43.6
Rights-of-way	675.4	666.2
Pipelines	8,211.5	8,035.8
Pumping equipment, buildings and tanks	2,500.0	2,233.0
Compressors, meters and other operating equipment	2,021.3	1,989.8
Vehicles, office furniture and equipment	335.5	322.0
Processing and treating plants	514.5	514.4
Construction in progress	2,252.3	2,077.7
Total property, plant and equipment	16,553.7	15,882.5
Accumulated depreciation	(2,803.9)	(2,705.7)
Property, plant and equipment, net	$13,749.8	$13,176.8

In March 2014, we recorded asset retirement obligations, or ARO, of $100.6 million. Of that amount, $60.0 million is related to Line 6B and is recorded in “Accounts payable and other” with an offset to “Property, plant and equipment, net” in our statement of financial position and $40.6 million is related to Line 3, and is recorded in “Other long-term liabilities” 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 ARO’s are related to the decommissioning of these pipelines as we are completing Line 6B replacement work in 2014 and have recently announced 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 ARO 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.

7. DEBT

Credit Facilities

In September 2011, we entered into a credit agreement with Bank of America as administrative agent, and the lenders party thereto, which we refer to as the Credit Facility. The agreement is a committed senior unsecured revolving credit facility that originally permitted aggregate borrowings of up to, at any one time outstanding, \$2.0 billion, a letter of credit subfacility and a swing line subfacility. Effective September 26, 2012, we extended the maturity date to September 26, 2017, and amended our Credit Facility to adjust the base interest rates. On October 28, 2013, we amended our Credit Facility to extend the maturity date from September 26, 2017, to September 26, 2018, and to reduce the aggregate permitted borrowings under the Credit Facility up to, at any one time outstanding, \$1.975 billion.

On July 6, 2012, we entered into a credit agreement with JPMorgan Chase Bank, as administrative agent, and a syndicate of 12 lenders, which we refer to as the 364-Day Credit Facility. We refer to the 364-Day Credit Facility and the Credit Facility as the Credit Facilities. The agreement is a committed senior unsecured revolving credit facility that originally permitted aggregate borrowings of up to, at any one time outstanding, \$675.0 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. On February 8, 2013, we amended the 364-Day Credit Facility to reflect an increase in the lending commitments to \$1.1 billion.

On July 3, 2013, we amended our 364-Day Credit Facility to extend the revolving credit termination date to July 4, 2014 and to increase aggregate commitments under the facility by \$50.0 million. Furthermore, on July 24, 2013, we added a new lender and increased our aggregate commitments by an additional \$50.0 million. After these changes, our 364-day Credit Facility now provides to us aggregate lending commitments of \$1.2 billion.

On October 28, 2013, we amended our Credit Facilities to modify certain terms and conditions to accommodate MEP IPO and the transactions contemplated thereby. The amendments were effective November 13, 2013.

Our Credit Facilities provided an aggregate amount of approximately \$3.2 billion of bank credit, as of March 31, 2014, which we use to fund our general activities and working capital needs.

The amounts we may borrow under the terms of our Credit Facilities are reduced by the face amount of our letters of credit outstanding. It is our policy 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 such time. Taking that policy into account, at March 31, 2014, we could borrow approximately \$2.3 billion under the terms of our Credit Facilities, determined as follows:

	(in millions)
Total credit available under Credit Facilities	\$3,175.0
Less: Amounts outstanding under Credit Facilities	—
Principal amount of commercial paper outstanding	690.0
Letters of credit outstanding	140.2
Total amount we could borrow at March 31, 2014	\$2,344.8

Individual London Inter-Bank Offered Rate, or LIBOR rate, borrowings under the terms of our Credit Facilities may be renewed as LIBOR rate borrowings or as base rate borrowings at the end of each LIBOR rate interest period, which is typically a period of three months or less. These renewals do not constitute new borrowings under the Credit Facilities and do not require any cash repayments or prepayments. For the three month periods ended March 31, 2014 and 2013, we did not have any LIBOR rate borrowings or base rate borrowings.

Our Credit Facilities previously were amended to exclude up to $650 million of the costs associated with the remediation of the area affected by the crude oil releases on Lines 6A and 6B from the Earnings Before Interest, Taxes, Depreciation and Amortization, or EBITDA, component of the consolidated leverage ratio covenant in each of our Credit Facilities. On December 23, 2013, we amended the quarterly covenant compliance testing for each of the Credit Facilities. The amendment excludes from the definition of consolidated net income component of the consolidated leverage ratio covenant accrued but unpaid costs, expenses, fines, and penalties occurring after September 30, 2013, related to the remediation of the area affected by the crude oil releases on Lines 6A and 6B.

Our ability to comply with that covenant in the future will depend on our ability to generate sufficient internal cash flow, issue additional equity or reduce existing debt, each of which will be subject to prevailing economic conditions and other factors, including factors beyond our control. A failure to comply with that covenant could result in an event of default under the Credit Facilities, which would prohibit us from declaring or making distributions to our unitholders and would permit acceleration of, and termination of our access to, our indebtedness under the Credit Facilities, and may cause acceleration of our outstanding senior notes. Although we expect to be able to comply with this covenant under each of our Credit Facilities, there can be no assurance that in the future we will be able to do so or that our lenders will be willing to waive such non-compliance or further amend such covenants. As of March 31, 2014, we were in compliance with the terms of all of our financial covenants under the Credit Facilities.

On February 3, 2014, EEP entered into an uncommitted letter of credit arrangement, pursuant to which the bank may, on a discretionary basis and with no commitment, agree to issue standby letters of credit upon our request in an aggregate amount not to exceed $200.0 million. While the letter of credit arrangement is uncommitted and issuance of letters of credit is at the bank's sole discretion, we view this arrangement as liquidity enhancement as it allows EEP to potentially reduce its reliance on utilizing the committed Credit Facilities for issuance of letters of credit to support its hedging activities.

Commercial Paper

We have a commercial paper program that provides for the issuance of up to an aggregate principal amount of $1.5 billion of commercial paper and is supported by our Credit Facilities. We access the commercial paper market primarily to provide temporary financing for our operating activities, capital expenditures and acquisitions when the available interest rates we can obtain are lower than the rates available under our Credit Facilities. At March 31, 2014, we had $690.0 million in principal amount of commercial paper outstanding at a weighted average interest rate of 0.34%, excluding the effect of our interest rate hedging activities. Under our commercial paper program, we had net borrowings of approximately $390.1 million during the three month period ended March 31, 2014, which includes gross borrowings of $1,474.7 million and gross repayments of $1,084.6 million. 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 that the commercial paper we can issue is limited 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.

Senior Notes

All of our senior notes represent our unsecured obligations that rank equally in right of payment with all of our existing and future unsecured and unsubordinated indebtedness. Our senior notes are structurally subordinated to all existing and future indebtedness and other liabilities, including trade payables of our subsidiaries and the $200.0 million of senior notes issued by the Enbridge Energy, Limited Partnership, or OLP, which we refer to as the OLP Notes. The borrowings under our senior notes are non-recourse to our General Partner and Enbridge Management. All of our senior notes either pay or accrue interest semi-annually and have varying maturities and terms.

The OLP, our operating subsidiary that owns the Lakehead system, has $200.0 million of senior notes outstanding representing unsecured obligations that are structurally senior to our senior notes. All of the OLP Notes pay interest semi-annually and have varying maturities and terms.

Junior Subordinated Notes

The $400.0 million in principal amount of our fixed/floating rate, junior subordinated notes due 2067, which we refer to as the Junior Notes, represent our unsecured obligations that are subordinate in right of payment to all of our existing and future senior indebtedness. We issued the Junior Notes in September 2007 for proceeds of approximately $393.0 million net of underwriting discounts, commissions and offering expenses. The Junior Notes bear interest at a fixed annual rate of 8.05%, exclusive of any discounts or interest rate hedging activities, payable semi-annually in arrears on April 1 and October 1 of each year until October 1, 2017. After October 1, 2017, the Junior Notes will bear interest at a variable rate equal to the three-month LIBOR for the related interest period increased by 3.7975%, payable quarterly in arrears on January 1, April 1, July 1 and October 1 of each year beginning January 1, 2018. We may elect to defer interest payments on the Junior Notes for up to ten consecutive years on one or more occasions, but not beyond the final repayment date. Until paid, any interest we elect to defer will bear interest at the prevailing interest rate, compounded semi-annually during the period the Junior Notes bear interest at the fixed annual rate and quarterly during the period that the Junior Notes bear interest at a variable annual rate.

The Junior Notes do not restrict our ability to incur additional indebtedness. However, with limited exceptions, during any period we elect to defer interest payments on the Junior Notes, we cannot make cash distribution payments or liquidate any of our equity securities, nor can we or our subsidiaries make any principal and interest payments for any debt that ranks equally with or junior to the Junior Notes.

The scheduled maturity date for the Junior Notes is initially October 1, 2037, but we may extend the maturity date up to two times, on October 1, 2017 and October 1, 2027, in each case for an additional ten-year period. As a result, the scheduled maturity date may be extended to October 1, 2047 or October 1, 2057. Our obligation to repay the Junior Notes on the scheduled maturity date is limited by an agreement we refer to as the Replacement Capital Covenant, which we entered into in connection with our offering of the Junior Notes, but not as part of the Junior Notes. The Replacement Capital Covenant limits the types of financing sources we can use to repay the Junior Notes. We are required to repay the Junior Notes on the scheduled maturity date only to the extent the principal amount repaid does not exceed proceeds we have received from the issuance and sale of securities, that, among other attributes defined in the Replacement Capital Covenant, have characteristics that are the same or more equity-like than the Junior Notes. We refer to the securities that meet this characterization as qualifying capital securities. If we do not receive sufficient proceeds from the sale of qualifying capital securities to repay the Junior Notes by the scheduled maturity date, we must use our commercially reasonable efforts to raise sufficient proceeds from the sale of qualifying capital securities to permit repayment of the Junior Notes on the following quarterly interest payment date, and on each subsequent quarterly interest payment date until the Junior Notes are paid in full. Regardless of the amount of qualifying capital securities that we have issued and sold, the final repayment date is initially October 1, 2067. We may extend the final repayment date for an additional ten-year period on October 1, 2017, and as a result the final repayment date may be extended to October 1, 2077. We may extend the scheduled maturity date whether or not we also extend the final repayment date, and we may extend the final repayment date whether or not we extend the scheduled maturity date.

We may redeem the Junior Notes in whole at any time, or in part, prior to October 1, 2017, for a “make-whole” redemption price, and thereafter at a redemption price equal to the principal amount plus accrued and unpaid interest on the Junior Notes. We may also redeem the Junior Notes prior to October 1, 2017 in whole, but not in part, upon the occurrence of certain tax or rating agency events at specified redemption prices. Our right to optionally redeem the Junior Notes is also limited by the Replacement Capital Covenant, which limits the types of financing sources we can use to redeem the Junior Notes in the same manner as to repay the Junior Notes, as discussed in the above paragraph.

MEP Credit Agreement

On November 13, 2013, in connection with the closing of the Offering, MEP, Midcoast Operating, and their material domestic subsidiaries, entered into a Credit Agreement, which we refer to as the Credit Agreement, by and among us, as co-borrower and a guarantor, Midcoast Operating, as co-borrower and a guarantor, our material subsidiaries party thereto as guarantors, Bank of America, N.A., as administrative agent, letter of credit issuer, swing line lender and lender, and each of the other lenders party thereto.

The Credit Agreement is a committed senior revolving credit facility (with related letter of credit and swing line facilities) that permits aggregate borrowings of up to, at any one time outstanding, $850.0 million, including up to initially: (1) $90.0 million under the letter of credit facility; and (2) $75.0 million under the swing line facility. Subject to customary conditions, MEP may request that the lenders' aggregate commitments be increased to an amount not to exceed $1.0 billion. The facility matures in three years, subject to four one-year requests for extensions. At March 31, 2014, MEP was in compliance with the terms of their financial covenants.

Loans under the Credit Agreement accrue interest at a per annum rate by reference, at MEP's election, to the Eurodollar rate, which is equal to the LIBOR rate or a comparable or successor rate reasonably approved by the Administrative Agent, or base rate, in each case, plus an applicable margin. The applicable margin on Eurodollar (LIBOR) rate loans ranges from 1.75% to 2.75% and the applicable margin on base rate loans ranges from 0.75% to 1.75%, in each case determined based upon our total leverage ratio (as defined below) at the applicable time. At March 31, 2014, MEP had $250.0 million in outstanding borrowings under the Credit Agreement at a weighted average interest rate of 1.9%. Under the Credit Agreement, MEP had net repayments of approximately $85.0 million during the three month period ended March 31, 2014, which includes gross borrowings of $1,725.0 million and gross repayments of $1,810.0 million. A letter of credit fee is payable by the borrowers equal to the applicable margin for Eurodollar (LIBOR) rate loans times the daily amount available to be drawn under outstanding letters of credit. A commitment fee is payable by us equal to an applicable margin times the daily unused amount of the lenders' commitment, which applicable margin ranges from 0.30% to 0.50% based upon our total leverage ratio at the applicable time.

Each of our domestic material subsidiaries has unconditionally guaranteed all existing and future indebtedness and liabilities of the borrowers arising under the Credit Agreement and other loan documents, and each co-borrower has guaranteed all such indebtedness and liabilities of the other co-borrower. The Credit Agreement is unsecured but security will be provided upon occurrence of any of the following: (1) for two consecutive quarters, the Total Leverage Ratio as described below, exceeds 4.25 to 1.00, or 4.75 to 1.00 during acquisition periods, (2) uncured breach to certain terms and conditions of the Credit Agreement and (3) obtaining a non-investment grade initial debt rating from either S&P or Moody's.

The Credit Agreement also requires compliance with two financial covenants. The Partnership must not permit the ratio of consolidated funded debt to pro forma EBITDA (the total leverage ratio) of the Partnership and its consolidated subsidiaries (including Midcoast Operating), as of the end of any applicable four-quarter period, to exceed 5.00 to 1.00, or 5.50 to 1.00 during acquisition periods. The Partnership 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. These covenants are subject to exceptions and qualifications set forth in the Credit Agreement.

Fair Value of Debt Obligations

The table below presents the carrying amounts and approximate fair values of our debt obligations. The carrying amounts of our outstanding commercial paper and borrowings under our Credit Facilities and prior credit facilities approximate their fair values at March 31, 2014 and December 31, 2013, respectively, due to the short-term nature and frequent repricing of these obligations. The fair value of our outstanding commercial paper and borrowings under our Credit Facilities are included with our long-term debt obligations below since we have the ability to refinance the amounts on a long-term basis. The approximate fair values of our long-term debt obligations are determined 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.

	March 31, 2014		December 31, 2013	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(in millions)			
Commercial Paper	$ 690.0	$ 690.0	$ 300.0	$ 300.0
Credit Agreement	250.0	250.0	335.0	335.0
5.350% Senior Notes due 2014	200.0	207.4	200.0	210.0
5.875% Senior Notes due 2016	299.9	335.2	299.9	335.0
7.000% Senior Notes due 2018	99.9	119.8	99.9	118.6
6.500% Senior Notes due 2018	399.1	468.3	399.1	464.5
9.875% Senior Notes due 2019	500.0	668.2	500.0	663.9
5.200% Senior Notes due 2020	499.9	556.7	499.9	544.8
4.200% Senior Notes due 2021	599.1	619.1	599.1	599.7
7.125% Senior Notes due 2028	99.8	129.1	99.8	121.9
5.950% Senior Notes due 2033	199.8	230.7	199.8	214.4
6.300% Senior Notes due 2034	99.8	119.5	99.8	110.9
7.500% Senior Notes due 2038	399.2	543.1	399.0	503.4
5.500% Senior Notes due 2040	546.4	577.9	546.4	531.0
8.050% Junior subordinated notes due 2067	399.7	452.4	399.7	446.4
Total	$5,282.6	$5,967.4	$4,977.4	$5,499.5

8. PARTNERS' CAPITAL

Distribution to Partners

The following table sets forth our distributions, as approved by the board of directors of Enbridge Energy Management, or Enbridge Management, during the three month period ended March 31, 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)			
January 30, 2014	February 7, 2014	February 14, 2014	$0.54350	$213.7	$34.6	$0.7	$178.4

(1) We issued 1,241,652 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 interest in our consolidated subsidiary, Enbridge Energy, Limited Partnership, or the OLP, for the three month periods ended March 31, 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 United States 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, Wisconsin, which we refer to as the Mainline Expansion Projects.

	For the three month period ended March 31,	
	2014	**2013**
	(in millions)	
Series 1 Preferred interests		
Beginning balance	$1,160.7	$ —
Net income	22.5	—
Accretion of discount on preferred units	3.6	—
Distribution payable	(22.5)	—
Beneficial conversion feature of preferred units	(47.7)	—
Ending balance	$1,116.6	$ —
General and limited partner interests		
Beginning balance	$4,637.7	$4,774.9
Proceeds from issuance of partnership interests, net of costs	—	278.7
Net income (loss)	93.3	(83.3)
Distributions	(178.4)	(176.1)
Beneficial conversion feature of preferred units	47.7	—
Ending balance	$4,600.3	$4,794.2
Accumulated other comprehensive loss		
Beginning balance	$ (76.6)	$ (320.5)
Net realized income on changes in fair value of derivative financial instruments reclassified to earnings	11.2	6.0
Unrealized net income (loss) on derivative financial instruments	(81.2)	23.7
Ending balance	$ (146.6)	$ (290.8)
Noncontrolling interest		
Beginning balance	$1,975.6	$ 793.5
Capital contributions	289.7	22.8
Net income	36.3	15.6
Distributions to noncontrolling interest	(16.3)	(13.8)
Ending balance	$2,285.3	$ 818.1
Total partners' capital at end of period	$7,855.6	$5,321.5

Midcoast Energy Partner, L.P.

On November 13, 2013, MEP, a subsidiary of EEP, 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 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 EEP, 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 EEP. 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 EEP. At March 31, 2014, we owned 2.893% of outstanding MEP Class A units, 100% of the outstanding MEP Subordinated Units, 100% of MEP's general partner and 61% of the limited partner interests in Midcoast Operating.

Series 1 Preferred Unit Purchase Agreement

On May 7, 2013, the Partnership entered into the Series 1 Preferred Unit Purchase Agreement, or Purchase Agreement, with our General Partner pursuant to which we issued and sold 48,000,000 of our Series 1 Preferred Units, representing limited partner interests in the Partnership, for aggregate proceeds of approximately $1.2 billion. The closing of the transactions contemplated by the Purchase Agreement occurred on May 8, 2013.

The Preferred Units are entitled to annual cash distributions of 7.50% of the issue price, payable quarterly, which are subject to reset every five years. However, these quarterly cash distributions, during the first full eight quarters ending June 30, 2015, will accrue and accumulate, which we refer to as the Payment Deferral. Thus the Partnership will accrue, but not pay these amounts until the earlier of the fifth anniversary of the issuance of such Preferred Units or the redemption of such Preferred Units by the Partnership. The quarterly cash distribution for the three month period ended June 30, 2013 was prorated from May 8, 2013. The preferred unit distributions for the three month period ended March 31, 2014 were $22.5 million. On or after June 1, 2016, at the sole option of the holder of the Preferred Units, the Preferred Units may be converted into Class A Common Units, in whole or in part, at a conversion price of $27.78 per unit plus any accrued, accumulated and unpaid distributions, excluding the Payment Deferral, as adjusted for splits, combinations and unit distributions. At all other times, redemption of the Preferred Units, in whole or in part, is permitted only if: (1) the Partnership uses the net proceeds from incurring debt and issuing equity, which includes asset sales, in equal amounts to redeem such Preferred Units; (2) a material change in the current tax treatment of the Preferred Units occurs; or (3) the rating agencies' treatment of the equity credit for the Preferred Units is reduced by 50% or more, all at a redemption price of $25.00 per unit plus any accrued, accumulated and unpaid distributions, including the Payment Deferral.

The Preferred Units were issued at a discount to the market price of the common units into which they are convertible. This discount totaling $47.7 million represents a beneficial conversion feature and is reflected as an increase in common and i-unit unitholders' and General Partner's capital and a decrease in Preferred Unitholders' capital to reflect the fair value of the Preferred Units at issuance on the Partnership's consolidated statement of partners' capital for the three month period ended March 31, 2014. The beneficial conversion feature is considered a dividend and is distributed ratably from the issuance date of May 8, 2013 through the first conversion date, which is June 1, 2016, resulting in an increase in preferred capital and a decrease in common and subordinated unitholders' capital. The impact of the beneficial conversion feature of $3.6 million is also included in earnings per unit for the three month period ended March 31, 2014.

Proceeds from the Preferred Unit issuance were used by the Partnership to repay commercial paper, to finance a portion of its capital expansion program relating to its core liquids and natural gas systems and for general partnership purposes.

9. RELATED PARTY TRANSACTIONS

Investment in Midcoast Energy Partners

We allocated earnings from Midcoast Energy Partners in the amount of $0.2 million to our General Partner for its ownership of the MEP interest for the three month period ended March 31, 2014. We have presented this amount we allocated to our General Partner in "Net income attributable to noncontrolling interest" on our consolidated statements of income.

Distribution to MEP Partners

The following table presents distributions paid by MEP to us and their public Class A common unitholders during the three month period ended March 31, 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)	
January 29, 2014	February 14, 2014	$4.1	$3.6	$7.7

Joint Funding Arrangement for Alberta Clipper Pipeline

In July 2009, we entered into a joint funding arrangement to finance the construction of the United States segment of the Alberta Clipper Pipeline with several of our affiliates and affiliates of Enbridge Inc., or Enbridge, which we refer to as the Series AC. In March 2010, we refinanced $324.6 million of amounts we had outstanding and payable to our General Partner under the A1 Credit Agreement, a credit agreement between our General Partner and us to finance the Alberta Clipper Pipeline, by issuing a promissory note payable to our General Partner, which we refer to as the A1 Term Note. At such time we also terminated the A1 Credit Agreement. The A1 Term Note matures on March 15, 2020, bears interest at a fixed rate of 5.20% and has a maximum loan amount of $400.0 million. The terms of the A1 Term Note are similar to the terms of our 5.20% senior notes due 2020, except that the A1 Term Note has recourse only to the assets of the United States portion of the Alberta Clipper Pipeline and is subordinate to all of our senior indebtedness. Under the terms of the A1 Term Note, we have the ability to increase the principal amount outstanding to finance the debt portion of the Alberta Clipper Pipeline that our General Partner is obligated to make pursuant to the Alberta Clipper Joint Funding Arrangement for any additional costs associated with our construction of the Alberta Clipper Pipeline that we incur after the date the original A1 Term Note was issued. The increases we make to the principal balance of the A1 Term Note will also mature on March 15, 2020. Pursuant to the terms of the A1 Term Note, we are required to make semi-annual payments of principal and accrued interest. The semi-annual principal payments are based upon a straight-line amortization of the principal balance over a 30 year period as set forth in the approved terms of the cost of service recovery model associated with the Alberta Clipper Pipeline, with the unpaid balance due in 2020. The approved terms for the Alberta Clipper Pipeline are described in the "Alberta Clipper United States Term Sheet," which is included as Exhibit I to the June 27, 2008 Offer of Settlement filed with the Federal Energy Regulatory Commission, or FERC, by the OLP and approved on August 28, 2008 (Docket No. OR08-12-000).

A summary of the cash activity for the A1 Term Note for the three month periods ended March 31, 2014 and 2013 are as follows:

	A1 Term Note March 31,	
	2014	2013
	(in millions)	
Beginning Balance	$318.0	$330.0
Repayments	(6.0)	(6.0)
Ending Balance	$312.0	$324.0

We allocated earnings derived from operating the Alberta Clipper Pipeline in the amount of $10.1 million to our General Partner for its 66.67% share of the earnings of the Alberta Clipper Pipeline for the three month period ended March 31, 2014. We also allocated $12.9 million of such earnings to our General Partner for the three month period ended March 31, 2013. 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 three month period ended March 31, 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)	
January 30, 2014	February 14, 2014	$6.4	$12.8	$19.2

Joint Funding Arrangement for Eastern Access Projects

In May 2012, the OLP amended and restated its limited 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 United States Upper Midwest and in Ontario, Canada for light crude oil produced in western Canada and the United States, which we refer to as the Eastern Access Projects. From May 2012 through June 27, 2013, our General Partner indirectly owned 60% of all assets, liabilities and operations related to the Eastern Access Projects. On June 28, 2013, we and certain of our affiliates entered into an agreement with our General Partner pursuant to which we exercised our option to decrease our economic interest and funding of the Eastern Access Projects from 40% to 25%. Additionally, within one year of the in-service date, currently scheduled for early 2016, we have the option to increase our economic interest by up to 15 percentage points at cost. We received $90.2 million from our General Partner in consideration for our assignment to it of this portion of our interest, determined based on the capital we had funded prior to June 28, 2013 pursuant to Eastern Access Projects.

Our General Partner has made equity contributions totaling $178.5 million to the OLP during the three month period ended March 31, 2014 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 $21.6 million to our General Partner for its ownership of the EA interest for the three month period ended March 31, 2014. We allocated earnings derived from the Eastern Access Projects in the amount of $2.7 million to our General Partner for the three month period ended March 31, 2013. 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 U.S. Mainline Expansion Projects

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. From December 2012 through June 27, 2013, the projects were jointly funded by our General Partner at 60% and the Partnership at 40%, under the Mainline Expansion Joint Funding Agreement, which parallels the Eastern Access Joint Funding Agreement. On June 28, 2013, we and certain of our affiliates entered into an agreement with our General Partner pursuant to which we exercised our option to decrease our economic interest and funding in the project from 40% to 25%. Within one year of the last project in-service date, scheduled for early 2016, the Partnership will also have the option to increase its economic interest held at that time by up to 15 percentage points at cost. We received $12.0 million from our General Partner in consideration for our assignment to it of this portion of our interest, determined based on the capital we had funded prior to June 28, 2013 pursuant to the Mainline Expansion Projects.

Our General Partner has made equity contributions totaling $74.3 million and $22.8 million to the OLP for the three month periods ended March 31, 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 $4.4 million to our General Partner for its ownership of the ME interest for the three month period ended March 31, 2014. We have presented this amount we allocated to our General Partner in "Net income attributable to noncontrolling interest" on our consolidated statements of income.

Related Party Transactions with Joint Venture

We have a 35% aggregate interest in the Texas Express NGL system, which is comprised of two joint ventures with third parties that together are constructing 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 March 31, 2014 and December 31, 2013 was $375.7 million and $371.3 million, respectively, which is included on our consolidated statements of financial position in "Equity investment in joint venture." For the three month period ending March 31, 2014 we recognized a $1.3 million equity loss in "Other income (expense)" on our consolidated statement of income related to our investment in the system.

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

Sale of Accounts Receivable

Certain of our subsidiaries entered into a receivables purchase agreement, dated June 28, 2013, which we refer to as the Receivables Agreement, with an indirect wholly-owned subsidiary of Enbridge which was amended on September 20, 2013 and again on December 2, 2013. The Receivables Agreement and the transactions contemplated thereby were approved by the special committee of the board of directors of Enbridge Management. Pursuant to the Receivables Agreement, the Enbridge subsidiary will purchase on a monthly basis, for cash, current accounts receivable and accrued receivables, or the receivables, of the respective subsidiaries initially up to a monthly maximum of $450.0 million. Following the sale and transfer of the receivables to the Enbridge subsidiary, the receivables are deposited in an account of that subsidiary, and ownership and control are vested in that subsidiary. The Enbridge subsidiary has no recourse with respect to the receivables acquired from these operating subsidiaries under the terms of and subject to the conditions stated in the Receivables Agreement. The Partnership and MEP acts in an administrative capacity as collection agent on behalf of the Enbridge subsidiary and can be removed at any time in the sole discretion of the Enbridge subsidiary. The Partnership has no other involvement with the purchase and sale of the receivables pursuant to the Receivables Agreement. The Receivables Agreement terminates on December 30, 2016.

Consideration for the receivables sold is equivalent to the carrying value of the receivables less a discount for credit risk. The difference between the carrying value of the receivables sold and the cash proceeds received is recognized in "Operating and administrative-affiliate" expense in our consolidated statements of income. For the three month period ended March 31, 2014, the cost stemming from the discount on the receivables sold was not material. For the three month period ended March 31, 2014, we sold and derecognized $1,296.7 million of receivables to the Enbridge subsidiary. For the three period month ended March 31, 2014, the cash proceeds were $1,296.4 million which was remitted to the Partnership through our centralized treasury system. As of March 31, 2014, $433.0 million of the receivables were outstanding from customers that had not been collected on behalf of the Enbridge subsidiary.

As of March 31, 2014, and December 31, 2013 we have $16.8 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 March 31, 2014.

10. COMMITMENTS AND CONTINGENCIES

Environmental Liabilities

We are subject to federal and state laws and regulations relating to the protection of the environment. Environmental risk is inherent to liquid hydrocarbon and natural gas pipeline operations, and we are, at times, subject to environmental cleanup and enforcement actions. We manage this environmental risk through appropriate environmental policies and practices to minimize any impact our operations may have on the environment. To the extent that we are unable to recover 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 March 31, 2014 and December 31, 2013, we had $25.5 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 at 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. There are no impacts to the local community, wildlife or water supply. In connection with this crude oil release, the cost estimate is approximately $4.4 million, excluding possible fines and penalties. We made a payment of $0.1 million during the first quarter and we have a remaining estimated liability of $4.3 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. As of March 31, 2014, our total cost estimate for the Line 6B crude oil release remained at $1,122.1 million. This total estimate is before insurance recoveries and excluding additional fines and penalties other than the fines and penalties of $29.6 million discussed in Lines 6A & 6B Fines and Penalties below. On March 14, 2013, we received an order from the Environmental Protection Agency, 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, with the exception of required dredging in and around Morrow Lake and its delta. We are in the process of working with the EPA to ensure this work is completed as soon as reasonably possible considering weather conditions.

For purposes of estimating our expected losses associated with the Line 6B crude oil release, we have included those costs that we considered probable and that could be reasonably estimated at March 31, 2014. Our estimates do not include amounts we have capitalized or any claims associated with the release that may later become evident and excludes amounts recoverable under insurance and excludes fines and penalties from other governmental agencies other than the PHMSA civil penalty described above. 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	$ 526
Environmental Consultants	200
Professional, regulatory and other	396
Total	$1,122

For the three month periods ended March 31, 2014 and 2013, we made payments of $41.8 million and $7.8 million, respectively, for costs associated with the Line 6B crude oil release. As of March 31, 2014 and December 31, 2013, we had a remaining estimated liability of $217.4 million and $258.9 million, respectively.

Lines 6A & 6B Fines and Penalties

At March 31, 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 March 31, 2014, our estimated costs to the Line 6B crude oil release included in the total $29.6 million in fines and penalties for the Line 6B crude oil release. Included in this total is $3.7 million in civil penalties assessed by PHMSA that we paid during the third quarter of 2012. The total also includes $22.0 million we recognized in the fourth quarter of 2013 related to an estimate of the minimum amount of civil penalties under the Clean Water Act of the United States in respect of the Line 6B crude oil release. 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 $22.0 million represents the minimum estimated amount which may be assessed, excluding costs of injunctive relief, if any, that may be agreed to with the relevant governmental agencies. Given the complexity of settlement negotiations, which we expect will continue, and the limited information available to assess the matter, we are unable to reasonably estimate the final penalty which might be incurred or to reasonably estimate a range of outcomes at this time. Discussions with governmental agencies regarding fines and penalties 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 March 31, 2014, we have exceeded the limits of coverage under this insurance policy. As of March 31, 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 expect to 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 will renew its comprehensive property and liability insurance programs which will be effective May 1, 2014 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 will increase to $30 million per event, from the current $10 million. In the unlikely event that multiple insurable incidents occur which exceed coverage limits 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 the Partnership has entered into with Enbridge, Midcoast Energy Partners, and other Enbridge subsidiaries.

Legal and Regulatory Proceedings

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

A number of governmental agencies and regulators have initiated investigations into the Line 6B crude oil release. Approximately 25 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. On July 2, 2012, PHMSA announced a Notice of Probable Violation, or NOPV, related to the Line 6B crude oil release, including a civil penalty of $3.7 million that we paid during the third quarter of 2012.

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.

11. DERIVATIVE FINANCIAL INSTRUMENTS AND HEDGING ACTIVITIES

Our net income and cash flows are subject to volatility stemming from changes in interest rates on our variable rate debt obligations and fluctuations in commodity prices of natural gas, NGLs, condensate, crude oil and fractionation margins. Fractionation margins represent the relative difference between the price we receive from NGL and condensate sales and the corresponding 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 2018 in accordance with our risk management policies.

Accounting Treatment

Effective January 1, 2014, the Partnership elected to prospectively change its presentation of derivative assets and liabilities from a net basis to a gross basis in the Consolidated Statements of Financial Position. This change was adopted to provide more granular information related to the future economic benefits available to, and obligations of, the Partnership 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.

We record all derivative financial instruments in our consolidated financial statements at fair market value, which we adjust each period for changes in the fair market value, and refer to as marking to market, or mark-to-market. The fair market value of these derivative financial instruments reflects the estimated amounts that we would pay to transfer a liability or receive to sell an asset in an orderly transaction with market participants to terminate or close the contracts at the reporting date, taking into account the current unrealized losses or gains on open contracts. We apply a mid-market pricing convention, or the "market approach," to value substantially all of our derivative instruments. Actively traded external market quotes, data from pricing services and published indices are used to value our 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.

In accordance with the applicable authoritative accounting guidance, if a derivative financial instrument does not qualify as a cash flow hedge, or is not designated as a cash flow hedge, the derivative is marked-to-market each period with the increases and decreases in fair market value recorded in our consolidated statements of income as increases and decreases in "Operating revenue," "Cost of natural gas" and "Power" for our commodity-based derivatives and "Interest expense" for our interest rate derivatives. Cash flow is only impacted to the extent the actual derivative contract is settled by making or receiving a payment to or from the counterparty or by making or receiving a payment for entering into a contract that exactly offsets the original derivative contract. Typically, we settle our derivative contracts when the physical transaction that underlies the derivative financial instrument occurs.

If a derivative financial instrument qualifies and is designated as a cash flow hedge, which is a hedge of a forecasted transaction or future cash flows, any unrealized mark-to-market gain or loss is deferred in "Accumulated other comprehensive income," also referred to as AOCI, a component of "Partners' capital" in our consolidated statements of financial position, until the underlying hedged transaction occurs. To the extent that the hedge instrument is effective in offsetting the transaction being hedged, there is no impact to the income statement until the underlying transaction occurs. At inception and on a quarterly basis, we formally assess whether the hedge contract is highly effective in offsetting changes in cash flows of hedged items. Any ineffective portion of a cash flow hedge's change in fair market value is recognized each period in earnings. Realized gains and losses on derivative financial instruments that are designated as hedges and qualify for hedge accounting are included in "Cost of natural gas" for commodity hedges and "Interest expense" for interest rate hedges in our consolidated statements of income in the period in which the hedged transaction occurs. Gains and losses deferred in AOCI related to cash flow hedges for which hedge accounting has been discontinued remain in AOCI until the underlying physical transaction occurs unless it is probable that the forecasted transaction will not occur by the end of the originally specified time period or within an additional two-month period of time thereafter. Generally, our preference is for our derivative financial instruments to receive hedge accounting treatment whenever possible to mitigate the non-cash earnings volatility that arises from recording the changes in fair value of our derivative financial instruments through earnings. To qualify for cash flow hedge accounting treatment as set forth in the authoritative accounting guidance, very specific requirements must be met in terms of hedge structure, hedge objective and hedge documentation.

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.

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 swaps) to hedge the relative difference between the injection price paid to purchase and store natural gas and the withdrawal price at which the natural gas is 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 injected and the price received upon withdrawal of the natural gas 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 natural gas 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 natural gas

is 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 natural gas is sold from storage. As a result, derivative financial instruments associated with our natural gas 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 Forward Contracts**—In our Natural Gas segment, we use forward contracts to fix the price of NGLs we purchase and store in inventory and to fix the price of NGLs that we sell from inventory to meet the demands of our customers that sell and purchase NGLs. A sub-group of physical NGL sales contracts with terms allowing for economic net settlement do not qualify for the normal purchases and normal sales, or NPNS, scope exception and are being marked-to-market each period with the changes in fair value recorded in earnings. As a result, our operating income is subject to additional volatility associated with fluctuations in NGL 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 sub-group of physical natural gas sales contracts with terms allowing for economic net settlement do not qualify for the NPNS scope exception, and are being marked-to-market each period with the changes 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.

- **Crude Forward Contracts—**In our Liquids segment, we use forward contracts to fix the price of crude we purchase and store in inventory and to fix the price of crude that we sell from inventory. A sub-group of physical crude contracts with terms allowing for economic net settlement do not qualify for NPNS scope exception and are being marked-to-market each period with the changes in fair value recorded in earnings. As a result, our operating income is subject to additional volatility associated with fluctuations in crude prices until the forward contracts are settled.

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:

	March 31, 2014	December 31, 2013
	(in millions)	
Other current assets	$ 26.5	$ 21.2
Other assets, net	57.0	74.4
Accounts payable and other [(1)]	(221.9)	(172.0)
Other long-term liabilities	(17.0)	(12.3)
	$(155.4)	$ (88.7)

(1) Includes $8.7 million and $16.7 million of cash collateral at March 31, 2014 and December 31, 2013, respectively.

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

We record the change in fair value of our highly effective cash flow hedges in AOCI until the derivative financial instruments are settled, at which time they are reclassified to earnings. Also included in AOCI are unrecognized losses of approximately $32.7 million associated with derivative financial instruments that qualified for and were classified as cash flow hedges of forecasted transactions that were subsequently de-designated. These losses are reclassified to earnings over the periods during which the originally hedged forecasted transactions affect earnings. During the three month period ended March 31, 2014, unrealized commodity hedge losses of $0.1 million were de-designated as a result of the hedges no longer meeting hedge accounting criteria. We estimate that approximately $197.8 million, representing unrealized net losses from our cash flow hedging activities based on pricing and positions at March 31, 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 three month period ended March 31, 2014.

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

	March 31, 2014	December 31, 2013
	(in millions)	
Counterparty Credit Quality [1]		
AAA	$ —	$ 0.3
AA	(69.6)	(49.7)
A[2]	(98.9)	(40.1)
Lower than A[3]	13.1	0.8
	$(155.4)	$(88.7)

(1) As determined by nationally-recognized statistical ratings organizations.
(2) Includes $16.7 million of cash collateral at December 31, 2013.
(3) Includes $8.7 million of cash collateral at March 31, 2014.

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. We are holding $8.7 million and $16.7 million in cash collateral on our asset exposures at March 31, 2014 and December 31, 2013, respectively. 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.

The ISDA® agreements and associated credit support, which govern our financial derivative transactions, contain no credit rating downgrade triggers that would accelerate the maturity dates of our outstanding transactions. A change in ratings is not an event of default under these instruments, and the maintenance of a specific minimum credit rating is not a condition to transacting under the ISDA® agreements. In the event of a credit downgrade, additional collateral may be required to be posted under the agreement if we are in a liability position to our counterparty, but the agreement will not automatically terminate and require immediate settlement of all future amounts due.

The ISDA® agreements, in combination with our master netting agreements, and credit arrangements governing our interest rate and commodity swaps require that collateral be posted per tiered contractual thresholds based on the credit rating of each counterparty. We generally provide letters of credit to satisfy such collateral requirements under our ISDA® agreements. These agreements will require additional collateral postings of up to 100% on net liability positions in the event of a credit downgrade below investment grade. Automatic termination clauses which exist are related only to non-performance activities, such as the refusal to post collateral when contractually required to do so. When we are holding an asset position, our counterparties are likewise required to post collateral on their liability (our asset) exposures, also determined by tiered contractual collateral thresholds. Counterparty collateral may consist of cash or letters of credit, both of which must be fulfilled with immediately available funds.

In the event that our credit ratings were to decline to the lowest level of investment grade, as determined by Standard & Poor's and Moody's, we would be required to provide additional amounts under our existing letters of credit to meet the requirements of our ISDA® agreements. For example, if our credit ratings had been at the lowest level of investment grade at March 31, 2014, we would have been required to provide additional letters of credit in the amount of $18.4 million.

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

	March 31, 2014	December 31, 2013
	(in millions)	
United States financial institutions and investment banking entities	$(130.1)	$(85.0)
Non-United States financial institutions [(1)]	(25.4)	0.8
Other	0.1	(4.5)
	$(155.4)	$(88.7)

(1) Includes $8.7 million and $16.7 million of cash collateral at March 31, 2014 and December 31, 2013, respectively.

We are holding $8.7 million and $16.7 million of cash collateral on our asset exposures, and we have provided letters of credit totaling $139.6 million and $76.1 million relating to our liability exposures pursuant to the margin thresholds in effect at March 31, 2014 and December 31, 2013, respectively, under our ISDA® agreements.

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 derivatives is directly with our counterparty and continues until the maturity or termination of the contracts.

Effect of Derivative Instruments on the Consolidated Statements of Financial Position

		Asset Derivatives		Liability Derivatives	
		Fair Value at		Fair Value at	
	Financial Position Location	March 31, 2014	December 31, 2013	March 31, 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	37.3	57.1	—	—
Interest rate contracts	Accounts payable and other[(2)]	—	11.9	(184.2)	(145.5)
Interest rate contracts	Other long-term liabilities	—	—	(10.1)	(11.3)
Commodity contracts	Other current assets	3.2	2.0	—	(0.6)
Commodity contracts	Other assets	2.8	3.5	—	(0.5)
Commodity contracts	Accounts payable and other	—	1.9	(10.7)	(12.7)
Commodity contracts	Other long-term liabilities	—	0.6	(0.9)	(1.4)
		43.3	85.1	(205.9)	(172.0)
Derivatives not designated as hedging instruments					
Commodity contracts	Other current assets	23.3	11.8	—	(0.1)
Commodity contracts	Other assets	16.8	17.6	—	(3.3)
Commodity contracts	Accounts payable and other	—	5.4	(18.1)	(16.3)
Commodity contracts	Other long-term liabilities	—	—	(6.1)	(0.2)
		40.1	34.8	(24.2)	(19.9)
Total derivative instruments		$83.4	$119.9	$(230.1)	$(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 $8.7 million and $16.7 million of cash collateral at March 31, 2014 and December 31, 2013, respectively.

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

Derivatives in Cash Flow Hedging Relationships	Amount of Gain (Loss) Recognized in AOCI on Derivative (Effective Portion)	Location of Gain (Loss) Reclassified from AOCI to Earnings (Effective Portion)	Amount of Gain (Loss) Reclassified from AOCI to Earnings (Effective Portion)	Location of Gain (Loss) Recognized in Earnings on Derivative (Ineffective Portion and Amount Excluded from Effectiveness Testing)[1]	Amount of Gain (Loss) Recognized in Earnings on Derivative (Ineffective Portion and Amount Excluded from Effectiveness Testing)[1]
			(in millions)		
For the three month period ended March 31, 2014					
Interest rate contracts	$(71.7)	Interest expense	$ (4.7)	Interest expense	$(5.7)
Commodity contracts	(0.1)	Cost of natural gas	(6.5)	Cost of natural gas	1.7
Total	$(71.8)		$(11.2)		$(4.0)
For the three month period ended March 31, 2013					
Interest rate contracts	$ 28.9	Interest expense	$ (7.5)	Interest expense	$(0.5)
Commodity contracts	(1.6)	Cost of natural gas	1.5	Cost of natural gas	0.5
Total	$ 27.3		$ (6.0)		$—

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

Components of Accumulated Other Comprehensive Income/(Loss)

	Cash Flow Hedges
	(in millions)
Balance at December 31, 2013	$ (76.6)
Other Comprehensive Income before reclassifications [1]	(80.0)
Amounts reclassified from AOCI [2] [3]	10.0
Tax benefit (expense)	—
Net other comprehensive income	$ (70.0)
Balance at March 31, 2014	$(146.6)

(1) Excludes NCI loss of $1.2 million reclassified from AOCI at March 31, 2014.

(2) Excludes NCI gain of $1.2 million reclassified from AOCI at March 31, 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 March 31,	
	2014	2013
	(in millions)	
Losses (gains) on cash flow hedges:		
Interest Rate Contracts [1]	$ 4.7	$ 7.5
Commodity Contracts [2] [3]	5.3	(1.5)
Total Reclassifications from AOCI	$10.0	$ 6.0

(1) Loss (gain) 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 $1.2 million reclassified from AOCI at March 31, 2014.

Effect of Derivative Instruments on Consolidated Statements of Income

Derivatives Not Designated as Hedging Instruments	Location of Gain or (Loss) Recognized in Earnings [1]	For the three month period ended March 31, 2014	For the three month period ended March 31, 2013 [6]
		Amount of Gain or (Loss) Recognized in Earnings [2] (in millions)	
Interest rate contracts	Interest expense[3]	$—	$—
Commodity contracts	Operating revenue[4]	(1.3)	(1.5)
Commodity contracts	Power	0.3	0.3
Commodity contracts	Cost of natural gas[5]	(6.4)	(2.4)
Total		$(7.4)	$(3.6)

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

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

(3) Includes settlement gains of $0.2 million for the three month period ended March 31, 2013.

(4) Includes settlement gains of $0.4 million and $0.8 million for the three month periods ended March 31, 2014 and 2013, respectively.

(5) Includes settlement losses of $8.5 million and $0.4 million for the three month periods ended March 31, 2014 and 2013, respectively.

(6) The effects of derivative instruments on consolidated statements of income for the three month period ended March 31, 2013 have been revised to include settlement gains on derivatives not designated as hedge instruments of $0.6 million. The revisions to the disclosure had no impact on previously reported net income or earnings per unit.

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

Offsetting of Financial Assets and Derivative Assets

	As of March 31, 2014		
	Gross Amount of Assets Presented in the Statement of Financial Position	Amount Not Offset in the Statement of Financial Position	Net Amount
	(in millions)		
Description:			
Derivatives	$83.4	$(26.9)	$56.5
Total	$83.4	$(26.9)	$56.5

Offsetting of Financial Liabilities and Derivative Liabilities

	As of March 31, 2014		
	Gross Amount of Liabilities Presented in the Statement of Financial Position	Amount Not Offset in the Statement of Financial Position	Net Amount
	(in millions)		
Description:			
Derivatives [(1)]	$(238.8)	$26.9	$(211.9)
Total	$(238.8)	$26.9	$(211.9)

(1) Includes $8.7 million of cash collateral at March 31, 2014.

Inputs to Fair Value Derivative Instruments

The following table sets forth by level within the fair value hierarchy our financial assets and liabilities that were accounted for at fair value on a recurring basis as of March 31, 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.

We categorize 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, as Level 2. This category includes both over-the-counter, or 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; (3) volatility factors; and (4) 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.

	March 31, 2014				December 31, 2013			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
	(in millions)							
Interest rate contracts [(1)]	$—	$(165.7)	$—	$(165.7)	$—	$(96.4)	$—	$(96.4)
Commodity contracts:								
Financial	—	3.3	(3.4)	(0.1)	—	6.4	(6.9)	(0.5)
Physical	—	—	3.2	3.2	—	—	(0.2)	(0.2)
Commodity options	—	—	7.2	7.2	—	—	8.4	8.4
Total	$—	$(162.4)	$ 7.0	$(155.4)	$—	$(90.0)	$ 1.3	$(88.7)

(1) Includes $8.7 million and $16.7 million of cash collateral at March 31, 2014 and December 31, 2013, respectively.

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 March 31, 2014	Valuation Technique	Unobservable Input	Range [1]			Units
				Lowest	Highest	Weighted Average	
	(in millions)						
Commodity Contracts - Financial							
Natural Gas	$(0.3)	Market Approach	Forward Gas Price	3.88	4.68	4.42	MMBtu
NGLs	$(3.1)	Market Approach	Forward NGL Price	1.01	2.18	1.35	Gal
Commodity Contracts - Physical							
Natural Gas	$ 2.3	Market Approach	Forward Gas Price	3.34	5.17	4.25	MMBtu
Crude Oil	$(1.2)	Market Approach	Forward Crude Price	87.93	106.27	100.05	Bbl
NGLs	$ 2.5	Market Approach	Forward NGL Price	0.01	2.31	1.11	Gal
Power	$(0.4)	Market Approach	Forward Power Price	34.23	45.35	38.00	MWh
Commodity Options							
Natural Gas, Crude and NGLs	$ 7.2	Option Model	Option Volatility	15%	77%	34%	
Total Fair Value	$ 7.0						

(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.

Quantitative Information About Level 3 Fair Value Measurements

Contract Type	Fair Value at December 31, 2013 [2]	Valuation Technique	Unobservable Input	Range[1]			Units
				Lowest	Highest	Weighted Average	
	(in millions)						
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 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 March 31, 2014. No transfers of assets between any of the Levels occurred during the period.

	Commodity Financial Contracts	Commodity Physical Contracts	Commodity Options	Total
		(in millions)		
Beginning balance as of January 1, 2014	$(6.9)	$(0.2)	$ 8.4	$ 1.3
Transfer in (out) of Level 3 [(1)]	—	—	—	—
Gains or losses:				
Included in earnings	(5.3)	2.0	(1.5)	(4.8)
Included in other comprehensive income	(1.1)	—	—	(1.1)
Purchases, issuances, sales and settlements:				
Purchases	—	—	0.2	0.2
Settlements [(2)]	9.9	1.4	0.1	11.4
Ending balance as March 31, 2014	$(3.4)	$ 3.2	$ 7.2	$ 7.0
Amount of changes in net assets attributable to the change in derivative gains or losses related to assets still held at the reporting date	$(1.2)	$ 2.0	$(1.1)	$ (0.3)
Amounts reported in operating revenue	$—	$ 0.8	$—	$ 0.8

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

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

Fair Value Measurements of Commodity Derivatives

The following table provides summarized information about the fair values of expected cash flows of our outstanding commodity based swaps and physical contracts at March 31, 2014 and December 31, 2013.

	At March 31, 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	872,000	$ 4.43	$ 4.28	$ 0.1	$—	$—	$ —
	NGL	653,750	$ 65.16	$ 65.99	$ 0.9	$(1.5)	$ 0.6	$ (0.4)
	Crude Oil	70,000	$100.82	$100.10	$ 0.1	$—	$—	$ —
Receive fixed/pay variable	Natural Gas	2,443,800	$ 4.00	$ 4.39	$—	$(1.0)	$ 0.1	$ (1.0)
	NGL	1,967,500	$ 54.50	$ 56.00	$ 4.8	$(7.7)	$ 4.8	$(12.7)
	Crude Oil	1,239,675	$ 94.93	$ 97.98	$ 1.8	$(5.6)	$ 3.4	$ (5.4)
Receive variable/pay variable	Natural Gas	38,490,000	$ 4.38	$ 4.38	$ 0.6	$(0.4)	$ 0.6	$ (0.1)
Physical Contracts								
Receive variable/pay fixed	Natural Gas	5,703,122	$ 4.46	$ 4.41	$ 0.4	$(0.1)	$—	$ —
	NGL	1,073,640	$ 57.57	$ 57.25	$ 1.2	$(0.9)	$ 0.9	$ (0.9)
	Crude Oil	243,713	$ 99.24	$ 99.81	$ 0.3	$(0.4)	$—	$ —
Receive fixed/pay variable	Natural Gas	23,485,419	$ 4.33	$ 4.33	$ 0.1	$(0.1)	$—	$ —
	NGL	1,197,064	$ 55.26	$ 56.68	$ 0.1	$(1.8)	$ 0.4	$ (2.6)
	Crude Oil	333,526	$ 99.25	$100.28	$ 0.3	$(0.7)	$—	$ (0.4)
Receive variable/pay variable	Natural Gas	89,130,497	$ 4.41	$ 4.40	$ 1.8	$(0.7)	$ 0.9	$ (0.4)
	NGL	8,029,834	$ 42.91	$ 42.48	$ 5.2	$(1.7)	$ 5.8	$ (3.7)
	Crude Oil	843,189	$ 97.13	$ 98.03	$ 3.4	$(4.1)	$ 1.1	$ (1.2)
Pay fixed	Power [4]	44,143	$ 38.00	$ 46.58	$—	$(0.4)	$—	$ (0.7)
Portion of contracts maturing in 2015								
Swaps								
Receive variable/pay fixed	Crude Oil	67,500	$ 92.58	$ 91.10	$ 0.1	$—	$—	$ —
Receive fixed/pay variable	Natural Gas	60,000	$ 4.52	$ 4.51	$—	$—	$—	$ —
	NGL	565,750	$ 51.33	$ 50.71	$ 1.4	$(1.1)	$ 1.5	$ (1.1)
	Crude Oil	865,415	$ 97.72	$ 89.89	$ 6.9	$(0.2)	$ 8.3	$ —
Receive variable/pay variable	Natural Gas	10,107,500	$ 4.32	$ 4.33	$ 0.1	$(0.1)	$ 0.1	$ —
Physical Contracts								
Receive fixed/pay variable	Natural Gas	3,158,951	$ 4.49	$ 4.50	$—	$—	$—	$ —
	NGL	54,760	$ 54.21	$ 52.91	$ 0.1	$—	$—	$ —
Receive variable/pay variable	Natural Gas	46,325,708	$ 4.24	$ 4.22	$ 1.2	$(0.4)	$ 0.5	$ (0.1)
	NGL	808,001	$ 71.16	$ 70.79	$ 0.4	$(0.1)	$—	$ —
Portion of contracts maturing in 2016								
Swaps								
Receive fixed/pay variable	Crude Oil	45,750	$ 99.31	$ 84.52	$ 0.7	$—	$ 0.7	$ —
Physical Contracts								
Receive variable/pay variable	Natural Gas	31,192,423	$ 3.97	$ 3.97	$ 0.7	$(0.5)	$ 0.1	$ —
Portion of contracts maturing in 2017								
Physical Contracts								
Receive variable/pay variable	Natural Gas	13,425,825	$ 4.17	$ 4.18	$ 0.3	$(0.4)	$—	$ —

(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 March 31, 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 $0.1 million of gains at December 31, 2013.

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

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

	At March 31, 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	3,300,000	$ 3.90	$ 4.46	$ 0.4	$—	$ 0.7	$—
	NGL	394,500	$53.04	$53.17	$ 2.3	$—	$ 2.9	$—
Calls (written)	NGL	206,250	$59.62	$54.36	$—	$(0.6)	$—	$(1.0)
Puts (written)	Natural Gas	1,729,000	$ 3.90	$ 4.49	$—	$(0.2)	$—	$(0.5)
Calls (purchased)	NGL	46,000	$50.40	$45.73	$ 0.2	$—	$—	$—
Portion of option contracts maturing in 2015								
Puts (purchased)	Natural Gas	4,015,000	$ 3.90	$ 4.20	$ 1.9	$—	$ 1.7	$—
	NGL	1,113,250	$50.64	$53.31	$ 6.1	$—	$ 6.0	$—
	Crude Oil	456,250	$85.00	$89.50	$ 2.3	$—	$ 1.8	$—
Calls (written)	Natural Gas	1,277,500	$ 5.05	$ 4.20	$—	$(0.4)	$—	$(0.3)
	NGL	292,000	$62.48	$57.59	$—	$(1.6)	$—	$(1.0)
	Crude Oil	456,250	$90.70	$89.50	$—	$(3.1)	$—	$(1.9)
Portion of option contracts maturing in 2016								
Puts (purchased)	Crude Oil	91,500	$80.00	$84.30	$ 0.6	$—	$—	$—
Calls (written)	Crude Oil	91,500	$87.00	$84.30	$—	$(0.7)	$—	$—

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

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

(3) The fair value is determined based on quoted market prices at March 31, 2014 and December 31, 2013, respectively, discounted using the swap rate for the respective periods to consider the time value of money.

Fair Value Measurements of Interest Rate Derivatives

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

				Fair Value (2) at	
Date of Maturity & Contract Type	Accounting Treatment	Notional	Average Fixed Rate (1)	March 31, 2014	December 31, 2013
			(dollars in millions)		
Contracts maturing in 2015					
Interest Rate Swaps—Pay Fixed	Cash Flow Hedge	$ 300	2.43%	$ (4.7)	$ (6.8)
Contracts maturing in 2017					
Interest Rate Swaps—Pay Fixed	Cash Flow Hedge	$ 400	2.21%	$ (13.2)	$ (13.8)
Contracts maturing in 2018					
Interest Rate Swaps—Pay Fixed	Cash Flow Hedge	$ 500	2.08%	$ 1.9	$ 3.3
Contracts settling prior to maturity					
2014—Pre-issuance Hedges (3)	Cash Flow Hedge	$1,850	4.27%	$(189.1)	$(132.7)
2016—Pre-issuance Hedges	Cash Flow Hedge	$ 500	2.87%	$ 40.0	$ 60.8

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

(2) The fair value is determined from quoted market prices at March 31, 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 $0.6 million of losses at March 31, 2014 and $7.1 million of losses at December 31, 2013.

(3) Includes $8.7 million and $16.7 million of cash collateral at March 31, 2014 and December 31, 2013, respectively.

12. INCOME TAXES

We are not a taxable entity for United States federal income tax purposes, or for the majority of states that impose an income tax. Taxes on our net income generally are borne by our unitholders through the allocation of taxable income. Our income tax expense results from the enactment of state income tax laws that apply to entities organized as partnerships by the State of Texas that are 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 three month periods ended March 31, 2014 and 2013. Our income tax expense is $2.0 million and $1.8 million for the three month period ended March 31, 2014 and 2013, respectively.

At March 31, 2014 and December 31, 2013, we have included a current income tax payable of $1.7 million and $0.9 million, respectively, in "Property and other taxes payable" on our consolidated statements of financial position. In addition, at March 31, 2014 and December 31, 2013, we have included a deferred income tax payable of $18.0 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.

13. SEGMENT INFORMATION

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

Each of our reportable segments is a business unit that offers different services and products that 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, the Partnership changed its 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:

	As of and for the three month period ended March 31, 2014			
	Liquids	Natural Gas	Corporate [(1)]	Total
	(in millions)			
Total revenue	$ 432.7	$1,965.6	$ —	$ 2,398.3
Less: Intersegment revenue	—	318.7	—	318.7
Operating revenue	432.7	1,646.9	—	2,079.6
Cost of natural gas	—	1,488.7	—	1,488.7
Environmental costs, net of recoveries	5.0	—	—	5.0
Operating and administrative	108.4	108.9	(0.3)	217.0
Power	50.4	—	—	50.4
Depreciation and amortization	66.8	37.0	—	103.8
	230.6	1,634.6	(0.3)	1,864.9
Operating income	202.1	12.3	0.3	214.7
Interest expense, net	—	—	76.9	76.9
Allowance for equity used during construction	—	—	20.7	20.7
Other income (expense) [(3)]	—	(1.3)	0.5	(0.8)
Income (loss) from continuing operations before income tax expense	202.1	11.0	(55.4)	157.7
Income tax expense	—	—	2.0	2.0
Net income (loss)	202.1	11.0	(57.4)	155.7
Less: Net income attributable to:				
Noncontrolling interest	—	—	36.3	36.3
Series 1 preferred unit distributions	—	—	22.5	22.5
Accretion of discount on Series 1 preferred units	—	—	3.6	3.6
Net income (loss) attributable to general and limited partner ownership interests in Enbridge Energy Partners, L.P.	$ 202.1	$ 11.0	$(119.8)	$ 93.3
Total assets [(2)]	$9,854.0	$5,194.9	$ 304.0	$15,352.9
Capital expenditures (excluding acquisitions)	$ 495.0	$ 50.2	$ 5.3	$ 550.5

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

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

(3) 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.

	Liquids	Natural Gas	Corporate [1]	Total
	As of and for the three month period ended March 31, 2013			
	(in millions)			
Total revenue	$ 332.9	$1,608.8	$ —	$ 1,941.7
Less: Intersegment revenue	—	248.7	—	248.7
Operating revenue	332.9	1,360.1	—	1,693.0
Cost of natural gas	—	1,191.4	—	1,191.4
Environmental costs, net of recoveries	178.5	—	—	178.5
Operating and administrative	86.7	107.8	0.4	194.9
Power	33.6	—	—	33.6
Depreciation and amortization	56.8	35.4	—	92.2
	355.6	1,334.6	0.4	1,690.6
Operating income (loss)	(22.7)	25.5	(0.4)	2.4
Interest expense, net	—	—	76.4	76.4
Allowance for equity used during construction	—	—	7.8	7.8
Other income	—	—	0.3	0.3
Income (loss) from continuing operations before income tax expense	(22.7)	25.5	(68.7)	(65.9)
Income tax expense	—	—	1.8	1.8
Net income (loss)	(22.7)	25.5	(70.5)	(67.7)
Less: Net income attributable to the noncontrolling interest	—	—	15.6	15.6
Net income (loss) attributable to general and limited partner ownership interests in Enbridge Energy Partners, L.P.	$ (22.7)	$ 25.5	$ (86.1)	$ (83.3)
Total assets [2]	$7,688.9	$5,275.2	$115.8	$13,079.9
Capital expenditures (excluding acquisitions)	$ 346.2	$ 68.4	$ 2.5	$ 417.1

(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.

14. 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 the Southern Access, Alberta Clipper and Eastern Access pipelines as well as for our Line 6B 75-mile Replacement 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 under or over collection of revenue in any given year, which is trued-up in the following year. Under the authoritative accounting provisions applicable to our regulated operations, over or under collections of revenue are recognized in the financial statements currently and these amounts are realized the following year. 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. The assets and liabilities that we recognize for regulatory purposes are recorded in "Other current assets" and "Accounts payable and other," respectively, on our consolidated statements of financial position.

Southern Access Pipeline

For the three month period ended March 31, 2014, we had over collected revenue for our Southern Access Pipeline primarily due to lower than anticipated power cost adjustments and lower than anticipated income tax allowance for our April 2013 surcharge filing. As a result, for the three month period ended March 31, 2014, we adjusted our revenues by a net decrease of $3.4 million on our consolidated statements of income with a corresponding increase in the regulatory liability on our consolidated statements of financial position at March 31, 2014. The amounts will be included in our tolls beginning July 2014 when we update our transportation rates.

For 2013, we under collected revenue for our Southern Access Pipeline primarily due to our actual volumes being lower than the forecasted volumes used for our April 2013 surcharge filing, partially offset by higher than anticipated power credit adjustments. As a result, in 2013, we increased revenues on our consolidated statements of income with a corresponding decrease in the regulatory liability on our consolidated statements of financial position. For the three month period ended March 31, 2014, we decreased our revenues by $1.7 million on our consolidated statement of income with a corresponding amount decreasing the regulatory asset on our consolidated statement of financial position at March 31, 2014. At March 31, 2014 and December 31, 2013, we had a $5.3 million and $7.0 million regulatory asset, respectively, on our consolidated statements of financial position related to this under collection. We will recover these amounts from our customers when we update our transportation rates to account for the lower delivered volumes than estimated starting in July 2014.

Alberta Clipper Pipeline

For the three month period ended March 31, 2014, we under collected revenue on our Alberta Clipper Pipeline primarily due to higher than anticipated power costs and higher than anticipated equity return used for our April 2013 surcharge filing, partially offset by a decreased income tax allowance. As a result, for the three month period ended March 31, 2014, we increased our revenues by $2.9 million, on our consolidated statement of income with a corresponding decrease in the regulatory liability on our consolidated statement of financial position at March 31, 2014 for the differences in transportation volumes. The amounts will be included in our tolls beginning July 2014 when we update our transportation rates.

For 2013, we under collected revenue on our Alberta Clipper Pipeline primarily due to our actual volumes being lower than forecasted volumes used for our April 2013 surcharge filing and our income tax rate and return on equity rate base being higher than anticipated, partially offset by higher than anticipated power credit adjustments. As a result, in 2013 we increased our revenues for the amounts we under collected and recorded a decrease in our regulatory liability. For the three month period ended March 31, 2014, we decreased our revenues by $1.9 million on our consolidated statement of income with a corresponding amount decreasing the regulatory asset on our consolidated statement of financial position at March 31, 2014. At March 31, 2014 and December 31, 2013 we had regulatory assets of $5.6 million and $7.5 million respectively in our consolidated statements of financial position for the difference in volumes. These amounts will be included in our tolls beginning July 2014 when we update our transportation rates to account for the lower delivered volumes.

Eastern Access Projects

For the three month period ended March 31, 2014, we under collected revenue on an expansion component of our Eastern Access Projects due to an increase in the capital rate base as various components of the project were placed into service. As a result, for the three month period ended March 31, 2014, we increased our revenue by $0.4 million on our consolidated statements of income with a corresponding decrease in the regulatory liability on our consolidated statement of financial position at March 31, 2014. The amounts will be collected in our tolls beginning July 2014 when we update our transportation rates.

For 2013, we over collected revenue on our expansion component of our Eastern Access Projects due to a delay in the in-service date. As a result, in 2013 we reduced our revenues on our consolidated statements of income with a corresponding increase in the regulatory liability on our consolidated statements of financial position at December 31, 2013. For the three month period ended March 31, 2014, we increased our revenues by \$2.6 million, on our consolidated statement of income with a corresponding amount reducing the regulatory liability on our consolidated statement of financial position. At March 31, 2014 and December 31, 2013 we had a regulatory liability of \$8.0 million and \$10.6 million, respectively. The amounts will be refunded through our tolls when we update our transportation rates which became effective July 2014.

Lakehead Line 6B 75-Mile Replacement Project

For the three month period ended March 31, 2014, we under collected revenue for our Lakehead Line 6B 75-Mile Replacement Project. As a result, for the three month period ended March 31, 2014, we increased our revenue by \$2.5 million on our consolidated statements of income with a corresponding decrease in the regulatory liability on our consolidated statements of financial position at March 31, 2014. The amounts will be recovered beginning July 2014 when we update our transportation rates.

For 2013, we under collected revenue for our Lakehead Line 6B 75-Mile Replacement Project due to the capital rate base being higher than anticipated. As a result, for year ended December 31, 2013, we increased our revenue on our consolidated statements of income with a corresponding decrease in the regulatory asset on our consolidated statements of financial position. For the three month period ended March 31, 2014, we decreased our revenues by \$1.0 million on our consolidated statement of income with a corresponding amount decreasing the regulatory asset on our consolidated statement of financial position. At March 31, 2014 and December 31, 2013 we had a regulatory asset of \$2.5 million and \$3.3 million, respectively. The amounts will be recovered beginning July 2014 when we update our transportation rates.

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 March 31, 2014 and December 31, 2013, we had \$4.0 million and \$6.1 million, respectively, in qualifying volume liabilities related to the Southern Access Pipeline on our statements of financial position. For the three month periods ended March 31, 2014 and 2013, we increased our revenues by \$2.1 million and \$3.1 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 collection to our customers. At March 31, 2014 and December 31, 2013, we had \$6.5 million and \$6.9 million, respectively, in property tax over collection 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 three month periods ended March 31, 2014 and 2013, we increased our revenues by \$1.7 million and \$1.5 million, respectively, on our consolidated statements of income with a corresponding amount reducing the contractual obligation on our consolidated statements of financial position.

Allowance for Equity Used During Construction

We are permitted to capitalize and recover costs for rate-making purposes that include an allowance for equity costs during construction, referred to as AEDC. In connection with construction of the Eastern Access Projects, Line 6B 75-mile Replacement and Mainline Expansion Projects, we recorded $20.7 million of AEDC in "Property, plant and equipment" on our consolidated statement of financial position at March 31, 2014, and corresponding $20.7 million of "Allowance for equity used during construction" in our consolidated statement of income for the three month period ended March 31, 2014. We recorded $7.8 million of AEDC in "Property, plant and equipment" on our consolidated statement of financial position at March 31, 2013, and corresponding $7.8 million of "Allowance for equity used during construction" in our consolidated statements of income for the three month period ended March 31, 2013.

FERC Transportation Tariffs

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 utilizes the System Expansion Project II and the Facility Surcharge Mechanism, or 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 average transportation rate for crude oil movements from the Canadian border to the Chicago, Illinois area by an average of approximately $0.26 per barrel, to an average of approximately $1.93 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.

We have delayed our annual April 1 tariff filing for our Lakehead system as we are currently in negotiations with the Canadian Association of Petroleum Producers, or CAPP, concerning certain components of the tariff rate structure. We expect to file revised rates in May 2014 with an effective date of July 1, 2014. This filing will adjust the rates to reflect any agreed upon changes in the tariff rate structure.

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 expansions 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 $0.09 per barrel, to an average of approximately $2.21 per barrel.

The April 1, 2013 tariff changes 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.

On May 31, 2013, we filed FERC tariffs with effective dates of July 1, 2013 for our Lakehead, 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 1.045923, which was issued by the FERC on May 15, 2013, in Docket No. RM93-11-000. The tariff filings are in part index filings in accordance with 18 C.F.R.342.3 and in part compliance filing with certain settlement agreements, which are not subject to FERC indexing. As an example, we increased the average transportation rate for crude oil movements on our Lakehead system from the Canadian border to Chicago, Illinois by $0.05 per barrel to an average of approximately $1.98 per barrel.

15. SUPPLEMENTAL CASH FLOWS INFORMATION

The following table provides supplemental information for the item labeled “Other” in the “Net cash provided by operating activities” section of our consolidated statements of cash flows.

	For the three month period ended March 31,	
	2014	2013
	(in millions)	
Amortization of debt issuance and hedging costs	$ 2.8	$ 2.1
State income taxes	0.7	—
Deferred income taxes	0.6	0.1
Texas Express long-term inventory (line fill)	0.3	—
Discount accretion	0.1	0.2
Adjustments of Marshall homes values	(1.1)	2.7
Gain on sale of assets	(0.3)	—
Allowance for interest used during construction	—	(2.8)
Loss on sale of assets	—	1.1
Other	(0.4)	0.2
	$ 2.7	$ 3.6

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 additions to property, plant and equipment to total capital expenditures (excluding “Investment in joint venture”):

	For the three month period ended March 31,	
	2014	2013
	(in millions)	
Additions to property, plant and equipment	$612.8	$404.9
Increase (decrease) in construction payables	(62.3)	12.2
Total capital expenditures (excluding “Investment in joint venture”)	$550.5	$417.1

16. RECENT ACCOUNTING PRONOUNCEMENTS NOT YET ADOPTED

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

17. SUBSEQUENT EVENTS

Distribution to Partners

On April 30, 2014, the board of directors of Enbridge Management declared a distribution payable to our partners on May 15, 2014. The distribution will be paid to unitholders of record as of May 8, 2014 of our available cash of $214.5 million at March 31, 2014, or $0.54350 per limited partner unit. Of this distribution, $178.5 million will be paid in cash, $35.3 million will be distributed in i-units to our i-unitholder, Enbridge Management, and $0.7 million will be retained from our General Partner in respect of the i-unit distribution to maintain its 2% general partner interest.

Distribution to Series AC Interests

On April 30, 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 $13.1 million to the noncontrolling interest in the Series AC, while $6.6 million will be paid to us.

Distribution to Series EA Interests

On April 30, 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 $6.5 million to the noncontrolling interest in the Series EA, while $2.5 million will be paid to us.

Distribution MEP Partners

On April 29, 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 May 15, 2014. The distribution will be paid to unitholders of record as of May 8, 2014, of MEP's available cash of $14.4 million at March 31, 2014, or $0.3125 per limited partner unit. MEP will pay $6.6 million to their public Class A common unitholders, while $7.8 million in the aggregate will be paid to us with respect to our Class A common units, subordinated units and Midcoast Holdings, L.L.C. with respect to its general partner interest.

Midcoast Operating Distribution

On April 29, 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 May 8, 2014. Midcoast Operating will pay $23.9 million to us and $15.3 million to MEP.

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

The following discussion and analysis of our financial condition and results of operations is based on and should be read in conjunction with our consolidated financial statements and the accompanying notes included in Item 1. *Financial Statements* of this report.

In May 2013, we formed Midcoast Energy Partners, L.P., or MEP. On November 13, 2013,MEP completed its initial public offering, or the Offering, of Class A common units, representing limited partner interests in MEP. On the same date, in connection with the closing of the Offering, certain transactions, among others, occurred pursuant to which we effectively conveyed to MEP all of our limited liability company interests in the general partner of the operating subsidiary of MEP, or Midcoast Operating, and a 39% limited partner interest in Midcoast Operating, in exchange for certain MEP Class A common units and MEP Subordinated Units, approximately $304.5 million in cash as reimbursement for certain capital expenditures with respect to the contributed businesses, and a right to receive $323.4 million in cash. In addition, in connection with the Offering and the closing of the underwriters' exercise of its over-allotment option, we received $47.0 million from MEP in its redemption of 2,775,000 of MEP Class A common units from us. At March 31, 2014, we owned 2.893% of the outstanding MEP Class A units, 100% of the outstanding MEP Subordinated Units, 100% of MEP's general partner and 61% of the limited partner interests in Midcoast Operating.

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, the Partnership changed its reporting segments. The Marketing segment was combined with the Natural Gas segment to form one new segment named "Natural Gas". There was no change 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 table reflects our operating income by business segment and corporate charges for the three month periods ended March 31, 2014 and 2013.

	For the three month period ended March 31,	
	2014	**2013**
	(unaudited; in millions)	
Operating income (loss)		
Liquids	$202.1	$(22.7)
Natural Gas	12.3	25.5
Corporate, operating and administrative	0.3	(0.4)
Total operating income	214.7	2.4
Interest expense	76.9	76.4
Allowance for equity used during construction	20.7	7.8
Other income (expense)	(0.8)	0.3
Income (loss) before income tax expense	157.7	(65.9)
Income tax expense	2.0	1.8
Net income (loss)	155.7	(67.7)
Less: Net income attributable to:		
Noncontrolling interest	36.3	15.6
Series 1 preferred unit distributions	22.5	—
Accretion of discount on Series 1 preferred units	3.6	—
Net income (loss) attributable to general and limited partner ownership interests in Enbridge Energy Partners, L.P.	$ 93.3	$(83.3)

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 $224.8 million increase in operating income for the three month period ended March 31, 2014 when compared to the same period of 2013:

- Decreased environmental expense of $173.5 million for the three month period ended March 31, 2014 as compared with the same period in 2013, primarily due to a decrease of $175.0 million in cost accruals related to Line 6b recognized in the first quarter of 2013 with no similar accruals in the first quarter of 2014;
- Increased revenue of $62.1 million for the three month period ended March 31, 2014 related to rate increases as a result of tariff filings that became effective April 1, 2013 and July 1, 2013;
- Increased average daily delivery volumes on our North Dakota system by $18.2 million for the three month period ended March 31, 2014 when compared to the same period in 2013;
- Increased rail revenue of $7.4 million on our Berthold Rail system which was placed in service in March of 2013; and
- Increased revenue from our ship or pay agreements of $7.2 million on our North Dakota Bakken system.

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

- Increased operating and administrative expenses of $21.7 million for the three month period ended March 31, 2014, when compared to the same period in 2013. This is due to increases of $6.5 million in operational costs, as well as higher workforce related costs, property taxes, and increased administrative, regulatory and compliance support necessary for our systems totaling $15.0 million.
- Increased power costs of $16.8 million for the three month period ended March 31, 2014 as compared to the same period in 2013 related to increased throughput; and
- Increased depreciation expense of $10.0 million for the three month period ended March 31, 2014, 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 for the three month period ended March 31, 2014 decreased $13.2 million, when compared to the same period in 2013, primarily due to the following:

- Decreased operating income of approximately $21.0 million for the three month period ended March 31, 2014, primarily due to reduced average daily volumes on our major systems primarily attributable to reduced and delayed drilling activity in the Anadarko and East Texas regions, respectively, in the first quarter when compared to the same period in 2013;
- Decreased operating revenue less the cost of natural gas derived from keep-whole processing earnings of $7.5 million when compared to the same period in 2013, due to a decline in total NGL production primarily caused by the Avinger plant shutdown from early January until mid-February of 2014;
- Decreased operating income of approximately $3.0 million for the three month period ended March 31, 2014, primarily due to the impact of sustained freezing temperatures which significantly disrupted producer well head production levels and our pipeline operations when compared to the same period in 2013;
- Increased depreciation and amortization expense of $1.6 million for the three month period ended March 31, 2014, as compared with the same period in 2013, due to additional assets that were put in service; and

- Decreased operating income of $1.4 million for the three month period ended March 31, 2014, due to reduced pricing spreads between our Conway and Mont Belvieu market hubs when compared with the same period in 2013.

The above factor was partially offset for the three month period ended March 31, 2014, as compared with the same period in 2013 primarily due to:

- Increased operating income of $12.7 million due to significant improvement in natural gas and NGL prices for the three month period ended March 31, 2014, when compared to the same period of 2013; and
- Increased operating income of $6.1 million for the three month period ended March 31, 2014, in unrealized, non-cash, mark-to-market net gains from derivative instruments that do not qualify for hedge accounting treatment, when compared to the same period in 2013.

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"

The changes in fair value of our derivatives are also presented as a reconciling item on our consolidated statements of cash flows. The following table presents the net changes in fair value associated with our derivative financial instruments:

	For the three month period ended March 31,	
	2014	**2013**
	(unaudited; in millions)	
Liquids segment		
Non-qualified hedges	$(2.2)	$(2.0)
Natural Gas segment		
Hedge ineffectiveness	1.7	0.5
Non-qualified hedges	2.9	(2.0)
Commodity derivative fair value net gains (losses)	2.4	(3.5)
Corporate		
Hedge ineffectiveness	(5.7)	(0.5)
Non-qualified interest rate hedges	—	(0.2)
Derivative fair value net gains (losses)	$(3.3)	$(4.2)

RESULTS OF OPERATIONS—BY SEGMENT

Liquids

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

	For the three month period ended March 31,	
	2014	2013
	(unaudited; in millions)	
Operating Results:		
Operating revenue	$432.7	$332.9
Environmental costs, net of recoveries	5.0	178.5
Operating and administrative	108.4	86.7
Power	50.4	33.6
Depreciation and amortization	66.8	56.8
Operating expenses	230.6	355.6
Operating income	$202.1	$ (22.7)
Operating Statistics		
Lakehead system:		
United States [(1)]	1,560	1,470
Province of Ontario [(1)]	440	366
Total Lakehead system deliveries [(1)]	2,000	1,836
Barrel miles (billions)	134	120
Average haul (miles)	746	726
Mid-Continent system deliveries [(1)]	211	222
North Dakota system:		
Trunkline [(1)]	242	124
Gathering [(1)]	3	4
Total North Dakota system deliveries [(1)]	245	128
Total Liquids Segment Delivery Volumes [(1)]	2,456	2,186

(1) Average barrels per day in thousands.

Three month period ended March 31, 2014 compared with the three month period ended March 31, 2013

The operating revenue of our Liquids segment increased $99.8 million for the three month period ended March 31, 2014 when compared with the same period in 2013, primarily due to the filing of tariffs that became effective July 1, 2013 and April 1, 2013 to increase the rates for our Lakehead and North Dakota and Ozark systems with Federal Energy Regulatory Commission, or FERC. The increase in rates accounted for $62.1 million of the increase in operating revenue for the three month period ended March 31, 2014 when compared to March 31, 2013. The rate increases that became effective July 1, 2013 and July 1, 2012 resulted from application of the index allowed by FERC. The rate increase effective April 1, 2013 primarily resulted from the annual tariff rate adjustment for our Lakehead system to reflect our projected costs and throughput for 2013, true-ups for the prior year for the Lakehead system and recovery of costs related to several of our major capital projects and SEPII integrity costs on our Lakehead system.

Additionally, operating revenue of our Liquids business increased for the three month period ended March 31, 2014 when compared with the same period in 2013 by $18.2 million due to higher average daily delivery volumes on our North Dakota system. Average daily volumes delivered increased from approximately 128,000 barrels per day during the three month period ended March 31, 2013 to 245,000 barrels per day during the three month period ended March 31, 2014. Our Lakehead system realized higher daily volumes of approximately 164,000 barrels per day which contributed to increased revenue of $15.0 million. This was negatively impacted by $15.2 million as a result of regulatory true-ups related to Lakehead toll revenues. Delivery volumes were forecasted to be higher in the April 1, 2013 toll filing as compared to actual volumes causing this negative impact. These amounts will be trued up and recovered in the Lakehead tariff that will be effective July 1, 2014.

Additionally, our operating revenue increased for the three month period ended March 31, 2014, when compared to the same period in 2013, due to an increase of $7.4 million from our Berthold Rail and Bakken Systems that was placed in service in March 2013. The increase is the result of the system being in place for the full first quarter of 2014.

Operating revenue also increased for the three month period ended March 31, 2014, when compared with the same period in 2013, due to an increase of $7.2 million in ship or pay contracts on our Bakken system. This is due to a full quarter of earnings from the Bakken system which went into service in March of 2013, as well as a stepped up demand charge for certain shippers. These long-term ship-or-pay contracts contain make-up-rights. Make-up-rights are earned by shippers 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.

Environmental costs, net of recoveries, decreased $173.5 million for the three month period ended March 31, 2014 when compared with the same period in 2013. Approximately $175.0 million, net of recoveries, of the decrease is related to the Line 6B crude oil release. On March 14, 2013, we received an order from the EPA, or the Environmental Protection Agency, which we refer to as the Order, that defined the scope which required additional containment and active recovery of submerged oil relating to the Line 6B crude oil release. During the three month period ended March 31, 2014, we had no cost accruals related to the Line 6B crude oil release compared to $175 million of cost accruals made during the three month period ended March 31, 2013.

The operating and administrative expenses of our Liquids business increased $21.7 million for the three month period ended March 31, 2014 when compared with the same period in 2013 primarily due to the increased costs of $6.5 million and $6.2 million related to operating and workforce expenses, respectively. These increases are primarily due to additional labor costs, additional costs associated with the Berthold Rail which was placed in service in March 2013 and increased administrative, regulatory and compliance support necessary for our systems.

Additionally, operating and administrative expenses increased as a result of increased property taxes of $5.5 million and higher costs related to our integrity program of $3.3 million.

Power costs increased $16.8 million for the three month period ended March 31, 2014 when compared to the same period in 2013 primarily as a result of increased volumes.

The increase in depreciation expense of $10.0 million for the three month period ended March 31, 2014 is directly attributable to the additional assets we have placed in service since the three month period ended March 31, 2013.

Future Prospects Update for Liquids

The table below and discussion summarizes the Partnership's 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-Service Date	Funding
	(in millions)		
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	Late 2015	Joint [2]
Line 61 (ME phase 2)	1,160	2015—2016	Joint [2]
Line 67 (ME phase 3)	240	2015	Joint [2]
Line 6B 75-mile Replacement Program	390	Q2 2013—Q1 2014	EEP
Sandpiper Project	2,600	Early 2016	Joint [5]
Line 3 Replacement Program	2,600	Second half 2017	EEP [6]

(1) Jointly funded 25% by the Partnership 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 the Partnership 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) Delayed, however, throughput impacts expected to be substantially mitigated by temporary system optimization actions.

(4) As of March 31, 2014, the following projects related to the Eastern Access Projects have been put into service: (1) Line 5 and (2) Line 62 Expansion.

(5) As of November 25, 2013, the Sandpiper Project is funded 62.5% by the Partnership 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 joint funding agreement with Enbridge Inc. is being finalized and approved by a special committee of independent directors of the board of EEP.

Line 3 Replacement Program

On March 3, 2014, we and Enbridge announced that shipper support was received to replace portions of the 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 to Superior, Wisconsin. Subject to finalization of a definitive cost estimate, regulatory and other approvals, the US L3R Program is targeted to be completed in the second half of 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.

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 directors of the board of EEP is considering a proposal from our General Partner, on behalf of Enbridge, to establish joint funding arrangements for the US L3R Program by creating an additional jointly owned series of partnership interests in the OLP. We anticipate that joint funding arrangements for the US L3R Program will be completed in 2014.

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 210,000 Bpd North Dakota system mainline, which now terminates at Clearbrook Terminal in Minnesota, adding 225,000 Bpd of capacity on the twin line between Tioga and Clearbrook with a new 24-inch diameter pipeline and 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, the Partnership, through its 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. As a result of Williston funding part of Sandpiper's construction, Williston will obtain an approximate 27% equity interest in NDPC at the in service date of Sandpiper targeted for early 2016.

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 February 12, 2014 and expect to receive a FERC decision in the summer of 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. The pipeline is expected to begin service in early 2016, subject to obtaining regulatory and other approvals.

Eastern Access Projects

Since October 2011, we and Enbridge have announced multiple expansion projects that will provide increased access to refineries in the United States 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. Portions of the existing 30-inch diameter pipeline are being replaced with 36-inch diameter pipe. The target in-service dates for the remaining Line 6B Replacement project were split into two phases, with the segment between Griffith and Stockbridge now expected to be completed in the second quarter of 2014 and the segment from Ortonville, Michigan to the international border at the St. Clair River is expected to be completed in the third quarter of 2014. As a result of more detailed engineering estimates coupled with issues with local ground terrain conditions including tie-ins, the expected capital cost increased by approximately $300 million. These projects, including the previously discussed Line 5 and Line 62 expansion completions, will now cost approximately $2.4 billion and will be 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, the Partnership will expand the Eastern Access Projects, which will include further expansion of the Line 6B component by increasing 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 now 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 the Line 6B component 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 the Partnership 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, we also announced further expansion of our mainline pipeline system, which included: (1) increasing capacity on the existing 36-inch diameter Alberta Clipper pipeline, or Line 67, between Neche, North Dakota into the Superior, Wisconsin Terminal from 450,000 Bpd to 570,000 Bpd; and (2) expanding of the existing 42-inch diameter Southern Access pipeline, or Line 61, between the Superior Terminal and the Flanagan Terminal near Pontiac, Illinois from 400,000 Bpd to 560,000 Bpd. These projects require only the addition of pumping horsepower and crude oil tanks at existing sites with no pipeline construction. The expected cost of these expansions is now approximately $380 million, which is a decrease of $40 million from the original estimated cost as a result of a reduction in scope. 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, the expansions will be undertaken on a full cost-of-service basis and are expected to be available for service in the third quarter of 2014 for the initial expansion to 570,000 Bpd and in 2015 for the expansion to 800,000 Bpd. It is anticipated that obtaining regulatory approval will take longer than originally planned although approval is expected before July 2015. A number of temporary system optimization actions are being undertaken to substantially mitigate any impact on throughput associated with the initial 120,000 Bpd capacity increase.

As part of the Light Oil Market Access Program announced in 2012, the capacity of our Lakehead System between Flanagan, Illinois, and Griffith, Indiana will be expanded by constructing a 76-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. Additionally, the capacity of our Southern Access pipeline, or Line 61, will be expanded to its full 1,200,000 Bpd potential with additional tankage requirements. The Line 61 expansion 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. Subject to regulatory and other approvals, the expansions are expected to begin service in 2015, with additional tankage expected to be completed in 2016.

In 2013, we announced further expansion of our Alberta Clipper pipeline, or Line 67, which will add an additional 230,000 Bpd of capacity at an estimated cost of approximately \$240 million. The expansion involves increased pumping horsepower, 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, the expansion is expected to be available for service in 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 the Partnership, under the Mainline Expansion Joint Funding Agreement, which parallels the Eastern Access Joint Funding. 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, the Partnership 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 U.S. Mainline Expansion Projects

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

Since October 2011, Enbridge also announced several complementary Eastern Access and Mainline Expansion Projects. These projects include: (1) reversal of Enbridge's Line 9A in western Ontario to permit crude oil movements eastbound from Sarnia as far as Westover, Ontario which was completed and placed into service in August 2013; (2) construction of a 35-mile pipeline adjacent to Enbridge's Toledo Pipeline, originating at the Partnership's 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 Ontario and Quebec; (5) expansions to add horsepower on existing lines on the Enbridge Mainline system from western Canada to the U.S. border; 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 and the Line 9B projects noted above are subject to fulfillment of certain conditions outlined under the Canadian National Energy Board, or NEB, approval received in March 2014. The conditions imposed by the NEB and the resultant impact on costs and tolls are currently under discussion with shippers, and may materially impact the scope and cost estimate of the Line 9B reversal and the Line 9B capacity expansion projects. 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

A key strength of the Partnership is our relationship with Enbridge. In 2011, Enbridge announced two major United States Gulf Coast market access pipeline projects, which, when completed, will pull more volume through the Partnership's 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 will have an initial capacity of approximately 600,000 Bpd and, subject to regulatory and other approvals, the pipeline is expected to be in service by the third quarter of 2014. 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 federal agencies, but no decision has yet been released.

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.

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 that is expected to more than double its capacity to 850,000 Bpd by the second quarter of 2014. This 30-inch diameter pipeline will follow the same route as the existing Seaway Pipeline. Included in the scope of this second line is 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, an 85-mile pipeline is being built 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. The new pipeline will offer incremental capacity of 750,000 Bpd, and is expected to be available in mid-2014.

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. Subject to regulatory and other approvals, the project is expected to be placed into service in 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 March 31,	
	2014	2013
	(unaudited; in millions)	
Operating revenues	$ 1,646.9	$ 1,360.1
Cost of natural gas	1,488.7	1,191.4
Operating and administrative	108.9	107.8
Depreciation and amortization	37.0	35.4
Operating expenses	1,634.6	1,334.6
Operating income (loss)	12.3	25.5
Other income (expense)	(1.3)	—
Net income (loss)	$ 11.0	$ 25.5
Operating Statistics (MMBtu/d)		
East Texas	971,000	1,252,000
Anadarko	824,000	964,000
North Texas	272,000	332,000
Total	2,067,000	2,548,000
NGL Production (Bpd)	82,171	88,498

Three month period ended March 31, 2014 compared with three month period ended March 31, 2013

The operating income of our Natural Gas business for the three month period ended March 31, 2014 decreased $13.2 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 decreased $10.5 million for the three month period ended March 31, 2014 as compared with the same period in 2013.

The segment gross margin for our Natural Gas segment was affected by the reduced production volumes which negatively affected segment gross margin by approximately $21.0 million for the three month period ended March 31, 2014 compared to the same period in 2013. The average daily volumes of our major systems for the three month period ended March 31, 2014 decreased by approximately 481,000 MMBtu/d, or 19%, when compared to the same period in 2013. The average NGL production for the three month period ended March 31, 2014 decreased by approximately 6,327 Bpd, or 7%, when compared to the same period in 2013. These decreases in volumes on our major systems were primarily attributable to reduced drilling activity by certain producers in the Anadarko region, the loss of a major customer, reduced dry gas drilling, and delayed drilling activity and well completions in East Texas.

A variable element of the operating results of our Natural Gas segment is derived from processing natural gas on our systems. Under percentage of liquids, or POL, contracts, we are required to pay producers a contractually fixed recovery of NGLs regardless of the NGLs we physically produce or our ability to process the NGLs from the natural gas stream. NGLs that are produced in excess of this contractual obligation in addition to 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 March 31, 2014 decreased $7.5 million from the same period in 2013. Within the decline in keep-whole earnings is the result of a decrease in total NGL production primarily due to the Avinger plant shutdown. The Avinger plant was shut down from early January until mid-February of 2014, which we estimate caused an unfavorable segment gross margin impact of $1.4 million for the three month period ended March 31, 2014.

In addition, our Anadarko and North Texas systems experienced sustained freezing temperatures during the first quarter, which reduced wellhead volumes by approximately 50,000 MMBtu/d for the three month period ended March 31, 2014, as compared with the same period in 2013. These sustained freezing temperatures caused our producers to have to shut down some of their production for a period of time due to frozen equipment or other logistical issues, including support vehicles and personnel being unable to access their wells. In addition, the sustained freezing temperatures caused similar logistical issues at our facilities. We estimate that the impact of the sustained freezing temperatures reduced our segment gross margin by approximately $3.0 million in the first quarter of 2014 compared with the same period in 2013. This weather, combined with reduced volumes of approximately 85,000 MMBtu/d, due to the loss of a large customer on our Anadarko system, reduced segment gross margin in the first quarter of 2014 compared with the same period in 2013.

The natural gas and NGL production volume outlook on our systems is expected to improve as we progress through 2014. We expect producer drilling plans to accelerate in each of our asset regions later in the year. Additionally, drilling activity by natural gas producers in all regions is targeting rich gas and oil prospects. This is notable in East Texas where existing processing capacity is full despite declining gas volumes. Completion of the Beckville Cryogenic Processing Plant, which is expected to commence service in early 2015, is expected to alleviate this capacity constraint. The Partnership continues to evaluate modifications to existing facilities in East Texas and North Texas to address this trend.

Offsetting the reduction in segment gross margin was the increase in unrealized, non-cash, mark-to-market net gains of $6.1 million for the three month period ended March 31, 2014 compared to the same period of 2013 due to gains on our equity gas hedges, hedge ineffectiveness, and overall physical commodity gains from the non-qualifying physical natural gas, NGL, and crude oil contracts. These gains were partially offset by losses on fractionating hedges.

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 month periods ended March 31, 2014 and 2013:

	For the three month period ended March 31,	
	2014	**2013**
	(unaudited; in millions)	
Hedge ineffectiveness	$1.7	$ 0.5
Non-qualified hedges	2.9	(2.0)
Derivative fair value gains	$4.6	$(1.5)

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.

Revenue for our Natural Gas business is derived from the fees or commodities we receive from the gathering, transportation, processing and treating of natural gas and NGLs for our customers. For the three month period ended March 31, 2014, improved prices for natural gas and NGLs increased segment gross margin by approximately $12.7 million when compared to the same period in 2013. Average natural gas prices improved approximately 48% per MMBtu based upon the New York Mercantile Exchange, or NYMEX, Henry Hub pricing index, for the three month period ended March 31, 2014, when compared to the same period in 2013. For the three months ended March 31, 2014, the prevailing price for NGLs increased approximately 17% per composite barrel at the Mont Belvieu pricing hub, while increasing approximately 23% per composite barrel at the Conway pricing hub, in each case as compared with the prevailing composite barrel prices for the same period in 2013. The price increase per composite barrel at the Conway pricing hub was driven by the sustained freezing temperatures in the Midwest.

Additionally, the segment gross margin of our Natural Gas segment decreased by approximately $1.4 million for the three months ended March 31, 2014 compared with the same period in 2013, due to the changes derived from purchasing some of our NGLs at the Conway market hub and selling them at the Mont Belvieu market hub. 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 of our Natural Gas segment remained relatively flat for the three month period ended March 31, 2014 compared to the same period in 2013.

Depreciation and amortization expense for our Natural Gas segment increased $1.6 million, for the three month period ended March 31, 2014 compared with the same period of 2013, due to additional assets that were put in service.

We recognized a $1.3 million equity loss 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. This loss is primarily due to deferred make-up rights. The Texas Express NGL system operates using ship or pay contracts. These ship or pay contracts contain make-up rights provisions, which are earned when minimum volume commitments are not utilized during the contract period but are also subject to contractual expiry periods. Revenue associated with these make-up rights is deferred when more than a remote chance of future utilization exists. For the three month period ended March 31, 2014, the deferred revenue on the ship or pay contracts amounted to $2.1 million.

In addition we received approximately $1.6 million in distributions from the Texas Express NGL system joint venture in the three month period ended March 31, 2014.

Future Prospects for Natural Gas

We intend to expand our natural gas gathering and processing services through 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. The paragraph below summarizes the Partnership's commercially secured project for the Natural Gas segment, which we expect to place into service in future periods.

Beckville Cryogenic Processing Plant

In April 2013, we announced plans to construct a cryogenic natural gas processing plant near Beckville in Panola County, Texas, which we refer to as the Beckville processing plant. This plant is expected to serve existing and prospective customers pursuing production in the Cotton Valley formation. We expect our Beckville processing plant to be capable of processing approximately 150 MMcf/d of natural gas and producing approximately 8,500 Bpd of NGLs to accommodate the additional liquids-rich natural gas being developed within this geographical area in which our East Texas system operates. We estimate the cost of constructing the plant to be approximately $145 million and expect it to commence service in early 2015. The project is funded by the Partnership and MEP based on their proportionate ownership percentages in Midcoast Operating, which is currently 61% and 39%, respectively.

Corporate

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

	For the three month period ended March 31,	
	2014	2013
	(unaudited; in millions)	
Operating Results:		
Operating and administrative expenses	$ (0.3)	$ 0.4
Operating income (loss)	0.3	(0.4)
Interest expense, net	76.9	76.4
Allowance for equity used during construction	20.7	7.8
Other income (expense)	0.5	0.3
Income tax expense	2.0	1.8
Net loss	(57.4)	(70.5)
Noncontrolling interest	36.3	15.6
Series 1 preferred unit distributions	22.5	—
Accretion of discount on Series 1 preferred units	3.6	—
Net loss attributable to general and limited partners	$(119.8)	$(86.1)

Our interest cost for the three month periods ended March 31, 2014 and 2013 is comprised of the following:

	For the three month period ended March 31,	
	2014	2013
	(unaudited; in millions)	
Interest expense, net	$76.9	$76.4
Interest capitalized	13.9	14.3
Interest cost incurred	$90.8	$90.7
Weighted average interest rate	6.7%	6.1%

Three month period ended March 31, 2014 compared with three month period ended March 31, 2013

The $13.1 million decrease in our net loss for the three month period ended March 31, 2014, as compared to the same period in 2013 was primarily attributable to the allowance for equity used during construction, or AEDC.

AEDC increased $12.9 million for the three month period ended March 31, 2014, compared with the corresponding period in 2013, primarily related to our Eastern Access projects, which also contributed to the decrease in net loss.

Other Matters

Alberta Clipper Pipeline Joint Funding Arrangement

In July 2009, we entered into a joint funding arrangement to finance construction of the United States 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 $10.1 million and $12.9 million to our General Partner for its

66.67% share of the earnings of the Alberta Clipper Pipeline for the three month periods ended March 31, 2014 and 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.

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 United States Upper Midwest and in Ontario, Canada for light crude oil produced in western Canada and the United States, which we refer to as the Eastern Access Projects. From May 2012 through June 27, 2013, our General Partner indirectly owned 60% all assets, liabilities and operations related to the Eastern Access Projects. On June 28, 2013, we and our affiliates entered into an agreement with our General Partner pursuant to which we exercised our option to decrease our economic interest and funding of the Eastern Access Projects from 40% to 25%. Additionally, within one year of the in-service date, scheduled for early 2016, we have the option to increase our economic interest by up to 15 percentage points at cost. We received $90.2 million from our General Partner in consideration for our assignment to it of this portion of our interest, determined based on the capital we had funded prior to June 28, 2013 pursuant to Eastern Access Projects.

We allocated earnings from the Eastern Access Projects in the amount of $21.6 million to our General Partner for its ownership of the EA interest for the three month periods ended March 31, 2014. We allocated earnings derived from the Eastern Access Projects in the amount of $2.7 million to our General Partner for the three month period ended March 31, 2013. 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. From December 2012 through June 27, 2013, the projects were jointly funded by our General Partner at 60% and the Partnership at 40%, under the Mainline Expansion Joint Funding Agreement, which parallels the Eastern Access Joint Funding Agreement. On June 28, 2013, we and our affiliates entered into an agreement with our General Partner pursuant to which we exercised our option to decrease our economic interest and funding in the projects from 40% to 25%. We received $12.0 million from our General Partner in consideration for our economic interest. Additionally, within one year of the in-service date, currently scheduled for 2016, we have the option to increase our economic interest held at that time by up to 15 percentage points at cost.

We allocated earnings from the Mainline Expansion Projects in the amount of $4.4 million to our General Partner for its ownership of the ME interest for the three month periods ended March 31, 2014. 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 credit agreement with Bank of America, as administrative agent, and the lenders party thereto, which we refer to as the Credit Facility, and our $1.2 billion credit agreement with

JPMorgan Chase Bank as administrative agent, and the lenders party thereto, 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.

As set forth in the following table, we had approximately $2.4 billion of liquidity available to us at March 31, 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 releases on Lines 6A and 6B. In addition, MEP had $0.7 billion of available liquidity from cash on hand and under its Credit Agreement as set forth in the following table.

	EEP	MEP
	(unaudited; in millions)	
Cash and cash equivalents	$ 88.9	$113.0
Total credit available under EEP's Credit Facilities	3,175.0	—
Total credit available under MEP's Credit Agreement	—	850.0
Amounts outstanding under Credit Agreement	—	250.0
Principal amount of commercial paper issuances	690.0	—
Letters of credit outstanding	140.2	—
Total	$2,433.7	$713.0

General

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

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

As of March 31, 2014, we had a working capital deficit of approximately $1.3 billion and approximately $2.4 billion of liquidity to meet our ongoing operational, investing and financing needs as of March 31, 2014, 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. In addition, MEP had $0.7 billion of available liquidity from cash on hand and under its Credit Agreement.

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 again 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.

Series 1 Preferred Unit Purchase Agreement

On May 7, 2013, the Partnership entered into the Series 1 Preferred Unit Purchase Agreement, or Purchase Agreement, with our General Partner pursuant to which we issued and sold 48,000,000 of our Series 1 Preferred Units, representing limited partner interests in the Partnership, for aggregate proceeds of approximately $1.2 billion. The closing of the transactions contemplated by the Purchase Agreement occurred on May 8, 2013.

The Preferred Units are entitled to annual cash distributions of 7.50% of the issue price, payable quarterly, which are subject to reset every five years. However, these quarterly cash distributions, during the first full eight quarters ending June 30, 2015, will accrue and accumulate, which we refer to as the Payment Deferral. Thus the Partnership will accrue, but not pay these amounts until the earlier of the fifth anniversary of the issuance of such Preferred Units or the redemption of such Preferred Units by the Partnership. The quarterly cash distribution for the three month period ended June 30, 2013 was prorated from May 8, 2013. The preferred unit distributions for the three month period ended March 31, 2014 were $22.5 million. On or after June 1, 2016, at the sole option of the holder of the Preferred Units, the Preferred Units may be converted into Class A Common Units, in whole or in part, at a conversion price of $27.78 per unit plus any accrued, accumulated and unpaid distributions, excluding the Payment Deferral, as adjusted for splits, combinations and unit distributions. At all other times, redemption of the Preferred Units, in whole or in part, is permitted only if: (1) the Partnership uses the net proceeds from incurring debt and issuing equity, which includes asset sales, in equal amounts to redeem such Preferred Units; (2) a material change in the current tax treatment of the Preferred Units occurs; or (3) the rating agencies' treatment of the equity credit for the Preferred Units is reduced by 50% or more, all at a redemption price of $25.00 per unit plus any accrued, accumulated and unpaid distributions, including the Payment Deferral.

The Preferred Units were issued at a discount to the market price of the common units into which they are convertible. This discount totaling $47.7 million represents a beneficial conversion feature and is reflected as an increase in common and i-unit unitholders' and General Partner's capital and a decrease in Preferred Unitholders' capital to reflect the fair value of the Preferred Units at issuance on the Partnership's consolidated statement of partners' capital for the three month period ended March 31, 2014. The beneficial conversion feature is considered a dividend and is distributed ratably from the issuance date of May 8, 2013 through the first conversion date, which is June 1, 2016, resulting in an increase in preferred capital and a decrease in common and subordinated unitholders' capital. The impact of the beneficial conversion feature of $3.6 million is also included in earnings per unit for the three month period ended March 31, 2014.

Proceeds from the Preferred Unit issuance were used by the Partnership to repay commercial paper, to finance a portion of its capital expansion program relating to its core liquids and natural gas systems and for general partnership purposes.

Midcoast Energy Partner, L.P.

On November 13, 2013, MEP, a subsidiary of EEP, 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 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 EEP, 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 EEP. 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 EEP. At March 31, 2014, we owned 2.893% of outstanding MEP Class A units, 100% of the outstanding MEP Subordinated Units, 100% of MEP's general partner and 61% of the limited partner interests in Midcoast Operating.

Investments

In March and September 2013, Enbridge Management completed public offerings of 10,350,000 and 8,424,686 Listed Shares, respectively, representing limited liability company interests with limited voting rights, at a price to the underwriters of $26.44 and $28.02 per Listed Share, respectively. Enbridge Management received net proceeds of $272.9 million and $235.6 million for the March and September 2013 issuances, respectively, which we subsequently invested in an equal number of the Partnership's i-units. We used the proceeds from our sale of i-units to finance a portion of our capital expansion program relating to the expansion of our core liquids and natural gas systems and for general corporate purposes.

Available Credit

Our two primary sources of liquidity are provided by our commercial paper program and our Credit Facilities. We have a $1.5 billion commercial paper program that is supported by our Credit Facilities, which we access primarily to provide temporary financing for our operating activities, capital expenditures and acquisitions when the interest rates available to us for commercial paper are more favorable than the rates available under our Credit Facilities.

Credit Facilities

In September 2011, we entered into a credit agreement with Bank of America as administrative agent, and the lenders party thereto, which we refer to as the Credit Facility. The agreement is a committed senior unsecured revolving credit facility that originally permitted aggregate borrowings of up to, at any one time outstanding, $2.0 billion, a letter of credit subfacility and a swing line subfacility. Effective September 26, 2012, we extended the maturity date to September 26, 2017, and amended our Credit Facility to adjust the base interest rates. On October 28, 2013, we amended our Credit Facility to extend the maturity date from September 26, 2017, to September 26, 2018, and to reduce the aggregate permitted borrowings under the Credit Facility up to, at any one time outstanding, $1.975 billion.

On July 6, 2012, we entered into a credit agreement with JPMorgan Chase Bank, as administrative agent, and a syndicate of 12 lenders, which we refer to as the 364-Day Credit Facility. We refer to the 364-Day Credit Facility and the Credit Facility as the Credit Facilities. The agreement is a committed senior unsecured revolving credit facility that originally permitted aggregate borrowings of up to, at any one time outstanding, $675.0 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. On February 8, 2013, we amended the 364-Day Credit Facility to reflect an increase in the lending commitments to $1.1 billion.

On July 3, 2013, we amended our 364-Day Credit Facility to extend the revolving credit termination date to July 4, 2014, and to increase aggregate commitments under the facility by $50.0 million. Furthermore, on

July 24, 2013, we added a new lender and increased our aggregate commitments by an additional $50.0 million. After these changes, our 364-day Credit Facility now provides to us aggregate lending commitments of $1.2 billion.

On October 28, 2013, we amended our Credit Facilities to modify certain terms and conditions to accommodate MEP IPO and the transactions contemplated thereby. The amendments were effective November 13, 2013.

Our Credit Facilities provided an aggregate amount of approximately $3.2 billion of bank credit, as of March 31, 2014, which we use to fund our general activities and working capital needs.

The amounts we may borrow under the terms of our Credit Facilities are reduced by the face amount of our letters of credit outstanding. It is our policy 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 such time. Taking that policy into account, at March 31, 2014, we could borrow approximately $2.3 billion under the terms of our Credit Facilities, determined as follows:

	(in millions)
Total credit available under Credit Facilities	$3,175.0
Less: Amounts outstanding under Credit Facilities	—
Principal amount of commercial paper outstanding	690.0
Letters of credit outstanding	140.2
Total amount we could borrow at March 31, 2014	$2,344.8

Individual London Inter-Bank Offered Rate, or LIBOR rate, borrowings under the terms of our Credit Facilities may be renewed as LIBOR rate borrowings or as base rate borrowings at the end of each LIBOR rate interest period, which is typically a period of three months or less. These renewals do not constitute new borrowings under the Credit Facilities and do not require any cash repayments or prepayments. For the three month periods ended March 31, 2014 and 2013, we did not have any LIBOR rate borrowings or base rate borrowings

Our Credit Facilities were previously amended to exclude up to $650 million of the costs associated with the remediation of the area affected by the crude oil releases on Lines 6A and 6B from the Earnings Before Interest, Taxes, Depreciation and Amortization, or EBITDA, component of the consolidated leverage ratio covenant in each of our Credit Facilities. On December 23, 2013, we amended the quarterly covenant compliance testing for each of the Credit Facilities. The amendment excludes from the definition of consolidated net income component of the consolidated leverage ratio covenant accrued but unpaid costs, expenses, fines, and penalties occurring after September 30, 2013, related to the remediation of the area affected by the crude oil releases on Lines 6A and 6B.

Our ability to comply with that covenant in the future will depend on our ability to generate sufficient internal cash flow, issue additional equity or reduce existing debt, each of which will be subject to prevailing economic conditions and other factors, including factors beyond our control. A failure to comply with that covenant could result in an event of default under the Credit Facilities, which would prohibit us from declaring or making distributions to our unitholders and would permit acceleration of, and termination of our access to, our indebtedness under the Credit Facilities, and may cause acceleration of our outstanding senior notes. Although we expect to be able to comply with this covenant under each of our Credit Facilities, there can be no assurance that in the future we will be able to do so or that our lenders will be willing to waive such non-compliance or further amend such covenants. As of March 31, 2014, we were in compliance with the terms of all of our financial covenants under the Credit Facilities.

On February 3, 2014, EEP entered into an uncommitted letter of credit arrangement, pursuant to which the bank may, on a discretionary basis and with no commitment, agree to issue standby letters of credit upon our request in an aggregate amount not to exceed $200.0 million. While the letter of credit arrangement is uncommitted and issuance of letters of credit is at the bank's sole discretion, we view this arrangement as liquidity enhancement as it allows EEP to potentially reduce its reliance on utilizing the committed Credit Facilities for issuance of letters of credit to support its hedging activities.

Commercial Paper

We have a commercial paper program that provides for the issuance of up to an aggregate principal amount of $1.5 billion of commercial paper and is supported by our Credit Facilities. We access the commercial paper market primarily to provide temporary financing for our operating activities, capital expenditures and acquisitions when the available interest rates we can obtain are lower than the rates available under our Credit Facilities. At March 31, 2014, we had $690.0 million in principal amount of commercial paper outstanding at a weighted average interest rate of 0.34%, excluding the effect of our interest rate hedging activities. Under our commercial paper program, we had net borrowings of approximately $390.1 million during the three month period ended March 31, 2014, which includes gross borrowings of $1,474.7 million and gross repayments of $1,084.6 million. 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 that the commercial paper we can issue is limited 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.

Senior Notes

All of our senior notes represent our unsecured obligations that rank equally in right of payment with all of our existing and future unsecured and unsubordinated indebtedness. Our senior notes are structurally subordinated to all existing and future indebtedness and other liabilities, including trade payables of our subsidiaries. The borrowings under our senior notes are non-recourse to our General Partner and Enbridge Management. All of our senior notes either pay or accrue interest semi-annually and have varying maturities and terms.

Junior Subordinated Notes

The $400.0 million in principal amount of our fixed/floating rate, junior subordinated notes due 2067, which we refer to as the Junior Notes, represent our unsecured obligations that are subordinate in right of payment to all of our existing and future senior indebtedness. We issued the Junior Notes in September 2007 for proceeds of approximately $393.0 million net of underwriting discounts, commissions and offering expenses. The Junior Notes bear interest at a fixed annual rate of 8.05%, exclusive of any discounts or interest rate hedging activities, payable semi-annually in arrears on April 1 and October 1 of each year until October 1, 2017. After October 1, 2017, the Junior Notes will bear interest at a variable rate equal to the three-month LIBOR for the related interest period increased by 3.7975%, payable quarterly in arrears on January 1, April 1, July 1 and October 1 of each year beginning January 1, 2018. We may elect to defer interest payments on the Junior Notes for up to ten consecutive years on one or more occasions, but not beyond the final repayment date. Until paid, any interest we elect to defer will bear interest at the prevailing interest rate, compounded semi-annually during the period the Junior Notes bear interest at the fixed annual rate and quarterly during the period that the Junior Notes bear interest at a variable annual rate.

The Junior Notes do not restrict our ability to incur additional indebtedness. However, with limited exceptions, during any period we elect to defer interest payments on the Junior Notes, we cannot make cash distribution payments or liquidate any of our equity securities, nor can we or our subsidiaries make any principal and interest payments for any debt that ranks equally with or junior to the Junior Notes.

The scheduled maturity date for the Junior Notes is initially October 1, 2037, but we may extend the maturity date up to two times, on October 1, 2017 and October 1, 2027, in each case for an additional ten-year period. As a result, the scheduled maturity date may be extended to October 1, 2047 or October 1, 2057. Our obligation to repay the Junior Notes on the scheduled maturity date is limited by an agreement we refer to as the Replacement Capital Covenant, which we entered into in connection with our offering of the Junior Notes, but not as part of the Junior Notes. The Replacement Capital Covenant limits the types of financing sources we can use to repay the Junior Notes. We are required to repay the Junior Notes on the scheduled maturity date only to the extent the principal amount repaid does not exceed proceeds we have received from the issuance and sale of securities, that, among other attributes defined in the Replacement Capital Covenant, have characteristics that are the same or more equity-like than the Junior Notes. We refer to the securities that meet this characterization as qualifying capital securities. If we do not receive sufficient proceeds from the sale of qualifying capital securities to repay the Junior Notes by the scheduled maturity date, we must use our commercially reasonable efforts to raise sufficient proceeds from the sale of qualifying capital securities to permit repayment of the Junior Notes on the following quarterly interest payment date, and on each subsequent quarterly interest payment date until the Junior Notes are paid in full. Regardless of the amount of qualifying capital securities that we have issued and sold, the final repayment date is initially October 1, 2067. We may extend the final repayment date for an additional ten-year period on October 1, 2017, and as a result the final repayment date may be extended to October 1, 2077. We may extend the scheduled maturity date whether or not we also extend the final repayment date, and we may extend the final repayment date whether or not we extend the scheduled maturity date.

We may redeem the Junior Notes in whole at any time, or in part, prior to October 1, 2017, for a “make-whole” redemption price, and thereafter at a redemption price equal to the principal amount plus accrued and unpaid interest on the Junior Notes. We may also redeem the Junior Notes prior to October 1, 2017 in whole, but not in part, upon the occurrence of certain tax or rating agency events at specified redemption prices. Our right to optionally redeem the Junior Notes is also limited by the Replacement Capital Covenant, which limits the types of financing sources we can use to redeem the Junior Notes in the same manner as to repay the Junior Notes, as discussed in the above paragraph.

MEP Credit Agreement

On November 13, 2013, in connection with the closing of the Offering, MEP, Midcoast Operating, and their material domestic subsidiaries, entered into a Credit Agreement, which we refer to as the Credit Agreement, by and among us, as co-borrower and a guarantor, Midcoast Operating, as co-borrower and a guarantor, our material subsidiaries party thereto as guarantors, Bank of America, N.A., as administrative agent, letter of credit issuer, swing line lender and lender, and each of the other lenders party thereto.

The Credit Agreement is a committed senior revolving credit facility (with related letter of credit and swing line facilities) that permits aggregate borrowings of up to, at any one time outstanding, $850.0 million, including up to initially: (1) $90.0 million under the letter of credit facility; and (2) $75.0 million under the swing line facility. Subject to customary conditions, MEP may request that the lenders’ aggregate commitments be increased to an amount not to exceed $1.0 billion. The facility matures in three years, subject to four one-year requests for extensions. At March 31, 2014, MEP was in compliance with the terms of their financial covenants.

Loans under the Credit Agreement accrue interest at a per annum rate by reference, at MEP’s election, to the Eurodollar rate, which is equal to the LIBOR rate or a comparable or successor rate reasonably approved by the Administrative Agent, or base rate, in each case, plus an applicable margin. The applicable margin on Eurodollar (LIBOR) rate loans ranges from 1.75% to 2.75% and the applicable margin on base rate loans ranges from 0.75% to 1.75%, in each case determined based upon our total leverage ratio (as defined below) at the applicable time. At March 31, 2014, MEP had $250.0 million in outstanding borrowings under the Credit Agreement at a weighted average interest rate of 1.9%. Under the Credit Agreement, MEP had net repayments of approximately

$85.0 million during the three month period ended March 31, 2014, which includes gross borrowings of $1,725.0 million and gross repayments of $1,810.0 million. A letter of credit fee is payable by the borrowers equal to the applicable margin for Eurodollar (LIBOR) rate loans times the daily amount available to be drawn under outstanding letters of credit. A commitment fee is payable by us equal to an applicable margin times the daily unused amount of the lenders' commitment, which applicable margin ranges from 0.30% to 0.50% based upon our total leverage ratio at the applicable time.

Each of our domestic material subsidiaries has unconditionally guaranteed all existing and future indebtedness and liabilities of the borrowers arising under the Credit Agreement and other loan documents, and each co-borrower has guaranteed all such indebtedness and liabilities of the other co-borrower. The Credit Agreement is unsecured but security will be provided upon occurrence of any of the following: (1) for two consecutive quarters, the Total Leverage Ratio as described below, exceeds 4.25 to 1.00, or 4.75 to 1.00 during acquisition periods, (2) uncured breach to certain terms and conditions of the Credit Agreement and (3) obtaining a non-investment grade initial debt rating from either S&P or Moody's.

The Credit Agreement also requires compliance with two financial covenants. The Partnership must not permit the ratio of consolidated funded debt to pro forma EBITDA (the total leverage ratio) of the Partnership and its consolidated subsidiaries (including Midcoast Operating), as of the end of any applicable four-quarter period, to exceed 5.00 to 1.00, or 5.50 to 1.00 during acquisition periods. The Partnership 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. These covenants are subject to exceptions and qualifications set forth in the Credit Agreement.

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 the Partnership's ability to efficiently raise capital. Accordingly, we have explored numerous options and determined that several joint funding arrangements would provide the best source of available capital to fund the expansion projects.

Joint Funding Arrangement for Alberta Clipper Pipeline

In July 2009, we entered into a joint funding arrangement to finance the construction of the United States segment of the Alberta Clipper Pipeline with several of our affiliates and affiliates of Enbridge. The Alberta Clipper Pipeline was mechanically complete in March 2010 and was ready for service on April 1, 2010.

In March 2010, we refinanced $324.6 million of amounts we had outstanding and payable to our General Partner under the A1 Credit Agreement by issuing a promissory note payable to our General Partner, which we refer to as the A1 Term Note. At such time we also terminated the A1 Credit Agreement. The A1 Term Note matures on March 15, 2020, bears interest at a fixed rate of 5.20% and has a maximum loan amount of $400 million. The terms of the A1 Term Note are similar to the terms of our 5.20% senior notes due 2020, except that the A1 Term Note has recourse only to the assets of the United States portion of the Alberta Clipper Pipeline. Under the terms of the A1 Term Note, we have the ability to increase the principal amount outstanding to finance the debt portion of the investment our General Partner is obligated to make pursuant to the Alberta Clipper Joint Funding Arrangement to finance any additional costs associated with the construction of our portion of the Alberta Clipper Pipeline we incur after the date the original A1 Term Note was issued. The increases we make to the principal balance of the A1 Term Note will also mature on March 15, 2020. At March 31, 2014, we had approximately $312.0 million outstanding under the A1 Term Note.

Our General Partner made no equity contributions to the OLP during the three month periods ended March 31, 2014 and 2013, respectively, to fund its equity portion of the construction costs associated with Alberta Clipper Pipeline. The OLP paid a distribution of $12.8 million and $13.8 million to our General Partner and its affiliate during the three month periods ended March 31, 2014 and 2013, respectively, for their noncontrolling interest in the Series AC, representing limited partner ownership interests of the OLP that are specifically related to the assets, liabilities and operations of the Alberta Clipper Pipeline.

We allocated earnings derived from operating the Alberta Clipper Pipeline in the amount of $10.1 million to our General Partner for its 66.67% share of the earnings of the Alberta Clipper Pipeline for the three month period ended March 31, 2014. We also allocated $12.9 million of such earnings to our General Partner for the three month period ended March 31, 2013. 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.

Joint Funding Arrangement for Eastern Access Projects

In May 2012, the OLP amended and restated its limited 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 United States Upper Midwest and in Ontario, Canada for light crude oil produced in western Canada and the United States, which we refer to as the Eastern Access Projects. From May 2012 through June 27, 2013, our General Partner indirectly owned 60% of all assets, liabilities and operations related to the Eastern Access Projects. On June 28, 2013, we and certain of our affiliates entered into an agreement with our General Partner pursuant to which we exercised our option to decrease our economic interest and funding of the Eastern Access Projects from 40% to 25%. Additionally, within one year of the in-service date, currently scheduled for early 2016, we have the option to increase our economic interest by up to 15 percentage points at cost. We received $90.2 million from our General Partner in consideration for our assignment to it of this portion of our interest, determined based on the capital we had funded prior to June 28, 2013 pursuant to Eastern Access Projects.

Our General Partner has made equity contributions totaling $178.5 million to the OLP during the three month period ended March 31, 2014 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 $21.6 million to our General Partner for its ownership of the EA interest for the three month period ended March 31, 2014. We allocated earnings derived from the Eastern Access Projects in the amount of $2.7 million to our General Partner for the three month period ended March 31, 2013. 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 Mainline Expansion Projects

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. From December 2012 through June 27, 2013, the projects were jointly funded by our General Partner at 60% and the Partnership at 40%, under the Mainline Expansion Joint Funding Agreement, which parallels the Eastern Access Joint Funding Agreement. On June 28, 2013, we and certain of our affiliates entered into an agreement with our General Partner pursuant to which we exercised our option to decrease our economic interest and funding in the project from 40% to 25%. Within one year of the last project in-service date, scheduled for early 2016, the Partnership will also have the option to increase its economic interest held at that time by up to 15 percentage points at cost. We received $12.0 million from our General Partner in consideration for our assignment to it of this portion of our interest, determined based on the capital we had funded prior to June 28, 2013 pursuant to the Mainline Expansion Projects.

Our General Partner has made equity contributions totaling $74.3 million and $22.8 million to the OLP for the three month periods ended March 31, 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 $4.4 million to our General Partner for its ownership of the ME interest for the three month period ended March 31, 2014. We have presented this amount we allocated to our General Partner in "Net income attributable to noncontrolling interest" on our consolidated statements of income.

Midcoast Energy Partners, L.P.

On November 13, 2013, as part of the Midcoast Energy Partners (MEP) Offering, EEP conveyed a 39% interest in Midcoast Operating, L.P. (Midcoast Operating) to MEP. 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.

Sale of Accounts Receivable

Certain of our subsidiaries entered into a receivables purchase agreement, dated June 28, 2013, which we refer to as the Receivables Agreement, with an indirect wholly-owned subsidiary of Enbridge. The Receivables Agreement was amended on September 20, 2013 and again on December 2, 2013. The Receivables Agreement and the transactions contemplated thereby were approved by the special committee of the board of directors of Enbridge Management. Pursuant to the Receivables Agreement, the Enbridge subsidiary will purchase on a monthly basis, for cash, current accounts receivable and accrued receivables, or the receivables, of the respective subsidiaries initially up to a monthly maximum of $450.0 million. Following the sale and transfer of the receivables to the Enbridge subsidiary, the receivables are deposited in an account of that subsidiary, and ownership and control are vested in that subsidiary. The Enbridge subsidiary has no recourse with respect to the receivables acquired from these operating subsidiaries under the terms of and subject to the conditions stated in the Receivables Agreement. The Partnership and MEP act in an administrative capacity as collection agents on behalf of the Enbridge subsidiary and can be removed at any time in the sole discretion of the Enbridge subsidiary. The Partnership has no other involvement with the purchase and sale of the receivables pursuant to the Receivables Agreement. The Receivables Agreement terminates on December 30, 2016.

Consideration for the receivables sold is equivalent to the carrying value of the receivables less a discount for credit risk. The difference between the carrying value of the receivables sold and the cash proceeds received is recognized in "Operating and administrative-affiliate" expense in our consolidated statements of income. For the three month period ended March 31, 2014, the cost stemming from the discount on the receivables sold was not material. For the three month period ended March 31, 2014, we sold and derecognized $1,296.7 million of receivables to the Enbridge subsidiary. For the three period month ended March 31, 2014, the cash proceeds were $1,296.4 million which was remitted to the Partnership through our centralized treasury system. As of March 31, 2014, $433.0 million of the receivables were outstanding from customers that had not been collected on behalf of the Enbridge subsidiary.

As of March 31, 2014, we have $16.8 million included in "Restricted cash" on our consolidated statements of financial position, consisting of cash collections related to the Receivables sold that have yet to be remitted to the Enbridge subsidiary as of March 31, 2014.

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 $1.7 billion on system enhancements 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 $1.4 billion from our General Partner based on our joint funding arrangement for the Eastern Access Projects and Mainline Expansion Projects and $155.0 million from MPC based on joint funding arrangement on the Sandpiper Project. We recognized capital expenditures of $557.8 million for the three month period ending March 31, 2014, including $27.5 million on core maintenance activities, $7.3 million in contributions to the Texas Express Pipeline and $289.7 million of expenditures that were financed by contributions from our General Partner and MPC via joint funding arrangements. At March 31, 2014, we had approximately $1.1 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 during 2014.

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 core maintenance or enhancement expenditures. Core maintenance 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 a portion of our expenditures for connecting natural gas wells, or well-connects, to our natural gas gathering systems as core maintenance expenditures. Enhancement expenditures include our capital expansion projects and other projects that improve the service capability of our existing assets, extend asset useful lives, increase capacities from existing levels, reduce costs or enhance revenues and enable us to respond to governmental regulations and developing industry standards.

We estimate our capital expenditures based upon our strategic operating and growth plans, which are also dependent upon our ability to produce or otherwise obtain the financing necessary to accomplish our growth objectives. The following table sets forth our estimates of capital expenditures we expect to make for system enhancement and core maintenance 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	$1,055
U.S. Mainline Expansions	830
Sandpiper	415
Line 6B 75-mile Replacement Program	15
Line 3 Replacement	100
Liquids Integrity Program	280
System Enhancements	260
Core Maintenance Activities	75
	3,030
Less joint funding from:	
General Partner [1]	1,410
Third parties	155
Liquids Total	$1,465
Natural Gas Projects	
Beckville Cryogenic Processing Plant	$ 105
System Enhancements	220
Core Maintenance Activities	60
	385
Less joint funding from:	
MEP	150
Natural Gas Total	235
TOTAL	$1,700

(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 finalized and approved by a special committee of independent directors of the board of EEP.

We maintain a comprehensive integrity management program for our pipeline systems, which relies on the latest technologies that include internal pipeline inspection tools. These internal pipeline inspection tools identify internal and external corrosion, dents, cracking, stress corrosion cracking and combinations of these conditions. We regularly assess the integrity of our pipelines utilizing the latest generations of metal loss, caliper and crack detection internal pipeline inspection tools. We also conduct hydrostatic testing to determine the integrity of our pipeline systems. Accordingly, we incur substantial expenditures each year for our integrity management programs.

Under our capitalization policy, expenditures that replace major components of property or extend the useful lives of existing assets are capital in nature, while expenditures to inspect and test our pipelines are usually considered operating expenses. 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 core maintenance capital will continue to increase due to the growth of our pipeline systems and the aging of portions of these systems. Core maintenance expenditures are expected to be funded by operating cash flows.

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

Environmental

Lakehead Line 6B Crude Oil Release

During the three month period ended March 31, 2014, our cash flows were impacted by the approximate $41.8 million we paid for the environmental remediation, restoration and cleanup activities resulting from the crude oil releases that occurred in 2010 on Line 6B of our Lakehead system. We expect to pay the majority of the total remaining estimated cost of $217.4 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 interest rates and commodity prices, as well as to reduce volatility to our cash flows. Based on our risk management policies, all of our derivative financial instruments are employed in connection with an underlying asset, liability and/or forecasted transaction and are not entered into with the objective of speculating on interest rates or commodity prices.

The following table provides summarized information about the timing and expected settlement amounts of our outstanding commodity derivative financial instruments based upon the market values at March 31, 2014 for each of the indicated calendar years:

	Notional	2014	2015	2016	2017	2018	Total
			(in millions)				
Swaps							
Natural gas [1]	51,973,300	$(0.7)	$ —	$—	$—	$—	$ (0.7)
NGL [2]	3,187,000	(3.5)	0.3	—	—	—	(3.2)
Crude Oil [2]	2,288,340	(3.7)	6.8	0.7	—	—	3.8
Options							
Natural gas—puts written [1]	1,729,000	(0.2)	—	—	—	—	(0.2)
Natural gas—puts purchased [1]	7,315,000	0.4	1.9	—	—	—	2.3
Natural gas—calls written [1]	1,277,500	—	(0.4)	—	—	—	(0.4)
NGL—puts purchased [2]	1,507,750	2.3	6.1	—	—	—	8.4
NGL—calls purchased [2]	46,000	0.2	—	—	—	—	0.2
NGL—calls written [2]	498,250	(0.6)	(1.6)	—	—	—	(2.2)
Crude Oil—puts purchased [2]	547,750	—	2.3	0.6	—	—	2.9
Crude Oil—calls written [2]	547,750	—	(3.1)	(0.7)	—	—	(3.8)
Forward contracts							
Natural gas [1]	212,421,945	1.4	0.8	0.2	(0.1)	—	2.3
NGL [2]	11,163,299	2.1	0.4	—	—	—	2.5
Crude Oil [2]	1,420,428	(1.2)	—	—	—	—	(1.2)
Power [3]	44,143	(0.4)	—	—	—	—	(0.4)
Totals		$(3.9)	$13.5	$ 0.8	$(0.1)	$—	$10.3

(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.

The following table provides summarized information about the timing and estimated settlement amounts of our outstanding interest rate derivatives calculated based on implied forward rates in the yield curve at March 31, 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	$1,200.0	$ (6.3)	$(7.7)	$ (3.8)	$ 1.6	$ 0.2	$—	$ (16.0)
Pre-issuance hedges [2]	$2,350.0	(189.1)	—	40.0	—	—	—	(149.1)
		$(195.4)	$(7.7)	$36.2	$ 1.6	$ 0.2	$—	$(165.1)

(1) Fair values are presented in millions of dollars and exclude credit adjustments of approximately $0.6 million of losses at March 31, 2014.

(2) Includes $8.7 million of cash collateral at March 31, 2014.

Cash Flow Analysis

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

	For the three month period ended March 31, 2014	2013	Variance 2014 vs. 2013 Increase (Decrease)
	(unaudited; in millions)		
Total cash provided by (used in):			
Operating activities	$ 210.8	$ 205.9	$ 4.9
Investing activities	(567.8)	(437.9)	(129.9)
Financing activities	394.1	245.6	148.5
Net decrease in cash and cash equivalents	37.1	13.6	23.5
Cash and cash equivalents at beginning of year	164.8	227.9	(63.1)
Cash and cash equivalents at end of period	$ 201.9	$ 241.5	$ (39.6)

Operating Activities

Net cash provided by our operating activities increased $4.9 million for the three month period ended March 31, 2014 compared to the same period in 2013, primarily due to an decrease in our working capital accounts of $49.9 million. This decrease due to our working capital accounts was offset by a $223.4 million increase in net income offset by non-cash items of $171.1 million for the three month period ended March 31, 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 three month period ended March 31,		Variance 2014 vs. 2013
	2014	2013	
	(unaudited; in millions)		
Changes in operating assets and liabilities, net of acquisitions:			
Receivables, trade and other	$(14.5)	$ (23.3)	$ 8.8
Due from General Partner and affiliates	4.5	(5.4)	9.9
Accrued receivables	74.6	142.0	(67.4)
Inventory	26.9	(14.6)	41.5
Current and long-term other assets	(4.8)	(8.0)	3.2
Due to General Partner and affiliates	(11.0)	29.3	(40.3)
Accounts payable and other	(85.0)	(67.6)	(17.4)
Environmental liabilities	(42.0)	(13.6)	(28.4)
Accrued purchases	(6.3)	(40.7)	34.4
Interest payable	5.7	6.9	(1.2)
Property and other taxes payable	9.1	2.1	7.0
Net change in working capital accounts	$(42.8)	$ 7.1	$(49.9)

The changes in our operating assets and liabilities, net of acquisitions as presented in our consolidated statements of cash flow for the three month period ended March 31, 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 accrued receivables decreased due to lower prices and volumes of NGLs partially offset by increased prices and volumes of natural gas from three month period ended March 31, 2014, compared to the same period in 2013. In addition, any sales of receivables due to our Receivables Agreement offset any activity in the accrued receivables balance. For more information, refer to the discussion above *Sale of Accounts Receivable.* Similar sales of receivables did not occur for the three month period ended March 31, 2013.

The above increase was partially offset by an increase in net income of $223.4 million offset by a $171.1 million increase in our non-cash items for the three month period ended March 31, 2014 compared to the three month period ended March 31, 2013. The decrease in non-cash items primarily consisted of the following:

- Decreased environmental costs of $169.1 million mainly attributed to $175.0 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 $4.4 million in additional estimated costs were recognized in three month period ended March 31, 2013; and
- Increased allowance for equity used during construction, or AEDC, of $12.9 million due to the Eastern Access Projects, partially offset by increased depreciation and amortization of $11.6 million due to additional projects placed in service as of March 31, 2014.

Investing Activities

Net cash used in our investing activities during the three month period ended March 31, 2014 increased by $129.9 million, compared to the same period of 2013, primarily due to the following:

- Increased additions to property, plant and equipment, net of construction payables in 2014 related to various enhancement projects of $207.9 million;

- Decreased cash contributions of $29.5 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; and
- Decreased restricted cash balance of $52.6 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. For more information, refer to discussion above, *Sale of Accounts Receivable*.

Financing Activities

Net cash provided by our financing activities increased $148.5 million for the three month period ended March 31, 2014, compared to the same period in 2013, primarily due to the following:

- Increased capital contributions from our General Partner and its affiliates in 2014 for its ownership interests in the Mainline Expansion Projects, Eastern Access Projects and Sandpiper Project of $266.9 million; and
- Increased net borrowings on our commercial paper of $250.1 million for the three months ended March 31, 2014.

Offsetting the increases above were the following:

- Decreased net proceeds from unit issuances, including our General Partner's contributions of $278.7 million from 2013 while we had no issuances in 2014; and
- Increased net repayments on MEP's Credit Agreement of $85.0 million in 2014 compared to no activity in 2013.

SUBSEQUENT EVENTS

Distribution to Partners

On April 30, 2014, the board of directors of Enbridge Management declared a distribution payable to our partners on May 15, 2014. The distribution will be paid to unitholders of record as of May 8, 2014 of our available cash of $214.5 million at March 31, 2014, or $0.54350 per limited partner unit. Of this distribution, $178.5 million will be paid in cash, $35.3 million will be distributed in i-units to our i-unitholder, Enbridge Management, and $0.7 million will be retained from our General Partner in respect of the i-unit distribution to maintain its 2% general partner interest.

Distribution to Series AC Interests

On April 30, 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 $13.1 million to the noncontrolling interest in the Series AC, while $6.6 million will be paid to us.

Distribution to Series EA Interests

On April 30, 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 $6.5 million to the noncontrolling interest in the Series EA, while $2.5 million will be paid to us.

Distribution MEP Partners

On April 29, 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 May 15, 2014. The distribution will be paid to unitholders of record as of May 8, 2014, of MEP's available cash of $14.4 million at March 31, 2014, or $0.3125 per limited partner unit. MEP will pay $6.6 million to their public Class A common unitholders, while $7.8 million in the aggregate will be paid to us with respect to our Class A common units, subordinated units and Midcoast Holdings, L.L.C. with respect to its general partner interest.

Midcoast Operating Distribution

On April 29, 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 May 8, 2014. Midcoast Operating will pay $23.9 million to us and $15.3 million to MEP.

REGULATORY MATTERS

FERC Transportation Tariffs

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 utilizes the System Expansion Project II and the Facility Surcharge Mechanism, or 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 average transportation rate for crude oil movements from the Canadian border to the Chicago, Illinois area by an average of approximately $0.26 per barrel, to an average of approximately $1.93 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.

We have delayed our annual April 1 tariff filing for our Lakehead system as we are currently in negotiations with the Canadian Association of Petroleum Producers, or CAPP, concerning certain components of the tariff rate structure. We expect to file revised rates in May 2014 with an effective date of July 1, 2014. This filing will adjust the rates to reflect any agreed upon changes in the tariff rate structure.

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 expansions 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 $0.09 per barrel, to an average of approximately $2.21 per barrel.

The April 1, 2013 tariff changes 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.

On May 31, 2013, we filed FERC tariffs with effective dates of July 1, 2013 for our Lakehead, 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 1.045923, which was issued by the FERC on May 15, 2013, in Docket No. RM93-11-000. The tariff filings are in part index filings in accordance with 18 C.F.R.342.3 and in part compliance filing with certain settlement agreements, which are not subject to FERC indexing. As an example, we increased the average transportation rate for crude oil movements on our Lakehead system from the Canadian border to Chicago, Illinois by $0.05 per barrel to an average of approximately $1.98 per barrel.

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 and fractionation margins. Fractionation margins represent the relative difference between the price we receive from NGL and condensate sales and the corresponding cost of natural gas we purchase for processing. Our interest rate risk exposure results from changes in interest rates on our variable rate debt and exists at the corporate level where our variable rate debt obligations are issued. Our exposure to commodity price risk exists within each of our segments. We use derivative financial instruments (i.e., futures, forwards, swaps, options and other financial instruments with similar characteristics) to manage the risks associated with market fluctuations in interest rates and commodity prices, as well as to reduce volatility of our cash flows. Based on our risk management policies, all of our derivative financial instruments are employed in connection with an underlying asset, liability and/or forecasted transaction and are not entered into with the objective of speculating on interest rates or commodity prices.

Interest Rate Derivatives

The table below provides information about our derivative financial instruments that we use to hedge the interest payments on our variable rate debt obligations that are sensitive to changes in interest rates and to lock in the interest rate on anticipated issuances of debt in the future. For interest rate swaps, the table presents notional amounts, the rates charged on the underlying notional amounts and weighted average interest rates paid by expected maturity dates. Notional amounts are used to calculate the contractual payments to be exchanged under the contract. Weighted average variable rates are based on implied forward rates in the yield curve at March 31, 2014.

Date of Maturity & Contract Type	Accounting Treatment	Notional	Average Fixed Rate (1)	Fair Value (2) at March 31, 2014	Fair Value (2) at December 31, 2013
			(dollars in millions)		
Contracts maturing in 2015					
Interest Rate Swaps—Pay Fixed	Cash Flow Hedge	$ 300	2.43%	$ (4.7)	$ (6.8)
Contracts maturing in 2017					
Interest Rate Swaps—Pay Fixed	Cash Flow Hedge	$ 400	2.21%	$ (13.2)	$ (13.8)
Contracts maturing in 2018					
Interest Rate Swaps—Pay Fixed	Cash Flow Hedge	$ 500	2.08%	$ 1.9	$ 3.3
Contracts settling prior to maturity					
2014—Pre-issuance Hedges (3)	Cash Flow Hedge	$1,850	4.27%	$(189.1)	$(132.7)
2016—Pre-issuance Hedges	Cash Flow Hedge	$ 500	2.87%	$ 40.0	$ 60.8

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

(2) The fair value is determined from quoted market prices at March 31, 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 $0.6 million of losses at March 31, 2014 and $7.1 million of losses at December 31, 2013.

(3) Includes $8.7 million and $16.7 million of cash collateral at March 31, 2014 and December 31, 2013, respectively.

Fair Value Measurements of Commodity Derivatives

The following table provides summarized information about the fair values of expected cash flows of our outstanding commodity based swaps and physical contracts at March 31, 2014 and December 31, 2013.

	At March 31, 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	872,000	$ 4.43	$ 4.28	$ 0.1	$—	$—	$ —
	NGL	653,750	$ 65.16	$ 65.99	$ 0.9	$(1.5)	$ 0.6	$ (0.4)
	Crude Oil	70,000	$100.82	$100.10	$ 0.1	$—	$—	$ —
Receive fixed/pay variable	Natural Gas	2,443,800	$ 4.00	$ 4.39	$—	$(1.0)	$ 0.1	$ (1.0)
	NGL	1,967,500	$ 54.50	$ 56.00	$ 4.8	$(7.7)	$ 4.8	$(12.7)
	Crude Oil	1,239,675	$ 94.93	$ 97.98	$ 1.8	$(5.6)	$ 3.4	$ (5.4)
Receive variable/pay variable	Natural Gas	38,490,000	$ 4.38	$ 4.38	$ 0.6	$(0.4)	$ 0.6	$ (0.1)
Physical Contracts								
Receive variable/pay fixed	Natural Gas	5,703,122	$ 4.46	$ 4.41	$ 0.4	$(0.1)	$—	$ —
	NGL	1,073,640	$ 57.57	$ 57.25	$ 1.2	$(0.9)	$ 0.9	$ (0.9)
	Crude Oil	243,713	$ 99.24	$ 99.81	$ 0.3	$(0.4)	$—	$ —
Receive fixed/pay variable	Natural Gas	23,485,419	$ 4.33	$ 4.33	$ 0.1	$(0.1)	$—	$ —
	NGL	1,197,064	$ 55.26	$ 56.68	$ 0.1	$(1.8)	$ 0.4	$ (2.6)
	Crude Oil	333,526	$ 99.25	$100.28	$ 0.3	$(0.7)	$—	$ (0.4)
Receive variable/pay variable	Natural Gas	89,130,497	$ 4.41	$ 4.40	$ 1.8	$(0.7)	$ 0.9	$ (0.4)
	NGL	8,029,834	$ 42.91	$ 42.48	$ 5.2	$(1.7)	$ 5.8	$ (3.7)
	Crude Oil	843,189	$ 97.13	$ 98.03	$ 3.4	$(4.1)	$ 1.1	$ (1.2)
Pay fixed	Power (4)	44,143	$ 38.00	$ 46.58	$—	$(0.4)	$—	$ (0.7)
Portion of contracts maturing in 2015								
Swaps								
Receive variable/pay fixed	Crude Oil	67,500	$ 92.58	$ 91.10	$ 0.1	$—	$—	$ —
Receive fixed/pay variable	Natural Gas	60,000	$ 4.52	$ 4.51	$—	$—	$—	$ —
	NGL	565,750	$ 51.33	$ 50.71	$ 1.4	$(1.1)	$ 1.5	$ (1.1)
	Crude Oil	865,415	$ 97.72	$ 89.89	$ 6.9	$(0.2)	$ 8.3	$ —
Receive variable/pay variable	Natural Gas	10,107,500	$ 4.32	$ 4.33	$ 0.1	$(0.1)	$ 0.1	$ —
Physical Contracts								
Receive fixed/pay variable	Natural Gas	3,158,951	$ 4.49	$ 4.50	$—	$—	$—	$ —
	NGL	54,760	$ 54.21	$ 52.91	$ 0.1	$—	$—	$ —
Receive variable/pay variable	Natural Gas	46,325,708	$ 4.24	$ 4.22	$ 1.2	$(0.4)	$ 0.5	$ (0.1)
	NGL	808,001	$ 71.16	$ 70.79	$ 0.4	$(0.1)	$—	$ —
Portion of contracts maturing in 2016								
Swaps								
Receive fixed/pay variable	Crude Oil	45,750	$ 99.31	$ 84.52	$ 0.7	$—	$ 0.7	$ —
Physical Contracts								
Receive variable/pay variable	Natural Gas	31,192,423	$ 3.97	$ 3.97	$ 0.7	$(0.5)	$ 0.1	$ —
Portion of contracts maturing in 2017								
Physical Contracts								
Receive variable/pay variable	Natural Gas	13,425,825	$ 4.17	$ 4.18	$ 0.3	$(0.4)	$—	$ —

(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 March 31, 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 $0.1 million of gains at December 31, 2013.

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

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

	At March 31, 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	3,300,000	$ 3.90	$ 4.46	$ 0.4	$—	$ 0.7	$—
	NGL	394,500	$53.04	$53.17	$ 2.3	$—	$ 2.9	$—
Calls (written)	NGL	206,250	$59.62	$54.36	$—	$(0.6)	$—	$(1.0)
Puts (written)	Natural Gas	1,729,000	$ 3.90	$ 4.49	$—	$(0.2)	$—	$(0.5)
Calls (purchased)	NGL	46,000	$50.40	$45.73	$ 0.2	$—	$—	$—
Portion of option contracts maturing in 2015								
Puts (purchased)	Natural Gas	4,015,000	$ 3.90	$ 4.20	$ 1.9	$—	$ 1.7	$—
	NGL	1,113,250	$50.64	$53.31	$ 6.1	$—	$ 6.0	$—
	Crude Oil	456,250	$85.00	$89.50	$ 2.3	$—	$ 1.8	$—
Calls (written)	Natural Gas	1,277,500	$ 5.05	$ 4.20	$—	$(0.4)	$—	$(0.3)
	NGL	292,000	$62.48	$57.59	$—	$(1.6)	$—	$(1.0)
	Crude Oil	456,250	$90.70	$89.50	$—	$(3.1)	$—	$(1.9)
Portion of option contracts maturing in 2016								
Puts (purchased)	Crude Oil	91,500	$80.00	$84.30	$ 0.6	$—	$—	$—
Calls (written)	Crude Oil	91,500	$87.00	$84.30	$—	$(0.7)	$—	$—

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

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

(3) The fair value is determined based on quoted market prices at March 31, 2014 and December 31, 2013, respectively, discounted using the swap rate for the respective periods to consider the time value of money.

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

	March 31, 2014	December 31, 2013
	(in millions)	
Counterparty Credit Quality [1]		
AAA	$ —	$ 0.3
AA	(69.6)	(49.7)
A [2]	(98.9)	(40.1)
Lower than A [3]	13.1	0.8
	$(155.4)	$(88.7)

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

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

(3) Includes $8.7 million of cash collateral at March 31, 2014.

Item 4. Controls and Procedures

We and Enbridge maintain systems of disclosure controls and procedures designed to provide reasonable assurance that we are able to record, process, summarize and report the information required to be disclosed in the reports that we file or submit under the Securities Exchange Act of 1934, as amended, or the Exchange Act, within the time periods specified in the rules and forms of the Securities and Exchange Commission, and that such information is accumulated and communicated to our management, including our principal executive and principal financial officers, as appropriate, to allow timely decisions regarding required disclosure. Our management, with the participation of our principal executive and principal financial officers, has evaluated the effectiveness of our disclosure controls and procedures as of March 31, 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 March 31, 2014.

PART II—OTHER INFORMATION

Item 1. Legal Proceedings

Refer to Part I, Item 1. *Financial Statements*, "Note 10. *Commitments and Contingencies*," which is incorporated herein by reference.

Item 1A. Risk Factors

There have been no material changes to the risk factors previously disclosed in our Annual Report on Form 10-K for the fiscal year ended December 31, 2013.

Item 6. Exhibits

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

SIGNATURES

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

ENBRIDGE ENERGY PARTNERS, L.P.
(Registrant)

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

Date: May 1, 2014

By: /s/ Mark A. Maki

Mark A. Maki
President and
Principal Executive Officer

Date: May 1, 2014

By: /s/ Stephen J. Neyland

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

Index of Exhibits

Each exhibit identified below is filed as a part of this Quarterly Report on Form 10-Q. Exhibits included in this filing are designated by an asterisk; all exhibits not so designated are incorporated by reference to a prior filing as indicated. Exhibits designated with a "+" constitute a management contract or compensatory plan arrangement required to be filed as an exhibit to this report pursuant to Item 6 of Form 10-Q.

Exhibit Number	Description
10.1+	Executive Employment Agreement between Enbridge Inc. and D. Guy Jarvis entered into on March 14, 2014 (incorporated by reference to Exhibit 10.1 to our Amended Current Report on Form 8-K/A, filed on March 18, 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: May 1, 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: May 1, 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 United States Code

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

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