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, 2012

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 238,043,964 Class A common units outstanding as of May 1, 2012.

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 contains forward-looking statements, which are typically identified by words such as "anticipate," "believe," "continue," "estimate," "expect," "forecast," "intend," "may," "plan," "position," "project," "strategy," "target," "could," "should" or "will" and similar words or statements, express or implied, suggesting future outcomes or statements regarding an outlook or the negative of those terms. Although we believe that these forward-looking statements are reasonable based on the information available on the dates these statements are made and processes used to prepare the information, these statements are not guarantees of future performance, and we caution you not to place undue reliance on these statements. By their nature, these statements involve a variety of assumptions, unknown risks, uncertainties and other factors, which may cause actual results, levels of activity and performance to differ materially from those expressed or implied by these statements. Material assumptions may include, among others, the expected supply of and demand for crude oil, natural gas and natural gas liquids, or NGLs; prices of crude oil, natural gas and NGLs; inflation and interest rates; operational reliability; and weather.

Our forward-looking statements are subject to risks and uncertainties pertaining to operating performance, regulatory parameters, weather, economic conditions, interest rates and commodity prices, including but not limited to, those risks and uncertainties discussed in this Quarterly Report on Form 10-Q and our other reports that we have filed or will file with the Securities and Exchange Commission, or SEC. The impact of any one risk, uncertainty or factor on a particular forward-looking statement is not determinable with certainty as these factors are interdependent, and our future course of action depends on the assessment of all information available at the relevant time by those responsible for the management of our operations. Except to the extent required by law, we assume no obligation to publicly update or revise any forward-looking statements made herein whether as a result of new information, future events or otherwise. All subsequent forward-looking statements, whether written or oral, attributable to us or persons acting on our behalf are expressly qualified in their entirety by these cautionary statements and, as such, may be updated in our future filings with the SEC. For additional discussion of risks, uncertainties and assumptions, see "Item 1A. Risk Factors" included in our Annual Report on Form 10-K for the fiscal year ended December 31, 2011.

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,	
	2012	2011
	(unaudited; in millions, except per unit amounts)	
Operating revenue (Note 10)	$1,819.5	$2,288.9
Operating expenses		
Cost of natural gas (Notes 4 and 10)	1,296.9	1,829.5
Environmental costs, net of recoveries (Note 9)	3.2	(34.6)
Oil measurement adjustments (Note 1)	(4.3)	(4.6)
Operating and administrative (Notes 1 and 9)	201.2	167.1
Power (Note 10)	41.2	35.6
Depreciation and amortization (Note 5)	83.6	88.4
	1,621.8	2,081.4
Operating income	197.7	207.5
Interest expense (Notes 6 and 10)	83.6	79.4
Other income (Note 9)	—	6.0
Income before income tax expense	114.1	134.1
Income tax expense (Note 11)	2.1	2.3
Net income	112.0	131.8
Less: Net income attributable to noncontrolling interest (Note 8)	13.0	14.7
Net income attributable to general and limited partner ownership interest in Enbridge Energy Partners, L.P.	$ 99.0	$ 117.1
Net income allocable to limited partner interests	$ 71.7	$ 96.7
Net income per limited partner unit (basic and diluted) (Note 2)	$ 0.25	$ 0.38
Weighted average limited partner units outstanding	284.7	252.8

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,	
	2012	2011
	(unaudited; in millions)	
Net income	$112.0	$131.8
Other comprehensive income (loss), net of tax benefit $0.1 and $0.5, respectively (Note 10)	35.4	(57.4)
Comprehensive income	147.4	74.4
Less: Comprehensive income attributable to noncontrolling interest (Note 8)	13.0	14.7
Comprehensive income attributable to general and limited partner ownership interests in Enbridge Energy Partners, L.P.	$134.4	$ 59.7

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, 2012	2011
	(unaudited; in millions)	
Cash provided by operating activities		
Net income	$ 112.0	$ 131.8
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization (Note 5)	83.6	88.4
Derivative fair value net losses (Note 10)	6.9	16.7
Inventory market price adjustments (Note 4)	2.4	—
Environmental costs, net of recoveries (Note 9)	(1.2)	(34.4)
Other (Note 15)	2.8	(6.8)
Changes in operating assets and liabilities:		
Receivables, trade and other	71.1	23.4
Due from General Partner and affiliates	8.4	(0.6)
Accrued receivables	73.7	119.6
Inventory (Note 4)	14.5	48.4
Current and long-term other assets (Note 10)	5.9	1.9
Due to General Partner and affiliates	17.7	0.5
Accounts payable and other (Notes 3 and 10)	33.4	23.4
Environmental liabilities (Note 9)	(52.3)	(90.2)
Accrued purchases	(132.3)	(85.8)
Interest payable	8.8	17.7
Property and other taxes payable	2.1	6.1
Net cash provided by operating activities	257.5	260.1
Cash used in investing activities		
Additions to property, plant and equipment (Note 5)	(261.3)	(181.6)
Joint venture contributions	(27.6)	—
Changes in construction payables	17.0	(6.3)
Other	(0.1)	(1.5)
Net cash used in investing activities	(272.0)	(189.4)
Cash used in financing activities		
Net proceeds from unit issuances	—	57.1
Distributions to partners (Note 7)	(159.4)	(132.0)
Repayments to General Partner (Note 8)	(6.0)	—
Net commercial paper borrowings (Note 6)	50.1	25.0
Borrowings from General Partner (Note 8)	—	2.6
Contribution from noncontrolling interest (Note 8)	—	3.2
Distributions to noncontrolling interest (Note 8)	(15.8)	(21.8)
Net cash used in financing activities	(131.1)	(65.9)
Net increase (decrease) in cash and cash equivalents	(145.6)	4.8
Cash and cash equivalents at beginning of year	422.9	144.9
Cash and cash equivalents at end of period	$ 277.3	$ 149.7

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

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

	March 31, 2012	December 31, 2011
	(unaudited; in millions)	
ASSETS		
Current assets		
Cash and cash equivalents (Note 3)	$ 277.3	$ 422.9
Receivables, trade and other, net of allowance for doubtful accounts of $1.5 in 2012 and 2011 (Note 9)	164.2	235.3
Due from General Partner and affiliates	15.1	23.3
Accrued receivables	434.2	507.9
Inventory (Note 4)	76.7	93.6
Other current assets (Note 10)	40.7	36.4
	1,008.2	1,319.4
Property, plant and equipment, net (Note 5)	9,621.1	9,439.4
Goodwill	246.7	246.7
Intangibles, net	262.4	265.3
Other assets, net (Note 10)	109.8	99.3
	$11,248.2	$11,370.1
LIABILITIES AND PARTNERS' CAPITAL		
Current liabilities		
Due to General Partner and affiliates	$ 72.6	$ 55.0
Accounts payable and other (Notes 3, 10 and 13)	520.0	478.6
Environmental liabilities (Note 9)	129.2	172.1
Accrued purchases	370.9	503.2
Interest payable	78.7	69.9
Property and other taxes payable (Note 11)	61.5	59.4
Note payable to General Partner (Note 8)	12.0	12.0
Current maturities of long-term debt (Note 6)	100.0	100.0
	1,344.9	1,450.2
Long-term debt (Note 6)	4,866.3	4,816.1
Note payable to General Partner (Note 8)	324.0	330.0
Other long-term liabilities (Notes 9, 10 and 11)	128.7	161.7
	6,663.9	6,758.0
Commitments and contingencies (Note 9)		
Partners' capital (Notes 7 and 8)		
Class A common units (238,043,964 at March 31, 2012 and December 31, 2011)	3,319.4	3,386.7
Class B common units (7,825,500 at March 31, 2012 and December 31, 2011)	80.0	82.2
i-units (39,168,162 and 38,566,334 at March 31, 2012 and December 31, 2011, respectively)	738.3	728.6
General Partner	285.0	285.6
Accumulated other comprehensive income (loss) (Note 10)	(281.1)	(316.5)
Total Enbridge Energy Partners, L.P. partners' capital	4,141.6	4,166.6
Noncontrolling interest (Note 8)	442.7	445.5
Total partners' capital	4,584.3	4,612.1
	$11,248.2	$11,370.1

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, 2012, our results of operations for the three month periods ended March 31, 2012 and 2011 and our cash flows for the three month periods ended March 31, 2012 and 2011. We derived our consolidated statement of financial position as of December 31, 2011 from the audited financial statements included in our Annual Report on Form 10-K for the fiscal year ended December 31, 2011. Our results of operations for the three month periods ended March 31, 2012 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 interim consolidated financial statements should be read in conjunction with our consolidated financial statements and notes thereto presented in our Annual Report on Form 10-K for the fiscal year ended December 31, 2011.

Comparative Amounts

We made a reclassification of $4.6 million for oil measurement gains from “Operating and administrative” to “Oil measurement adjustments” in our consolidated statement of income for the three month period ended March 31, 2011.

2. NET INCOME PER LIMITED PARTNER AND GENERAL PARTNER INTEREST

In February 2011, the board of directors of Enbridge Energy Management, L.L.C., or Enbridge Management, as delegate of our General Partner, approved a split of our units, which was effected by a distribution on April 21, 2011 of one common unit for each common unit outstanding and one i-unit for each i-unit outstanding to unit holders of record on April 7, 2011. As a result of this unit split, we have retrospectively restated the computation of our “Net income per limited partner unit (basic and diluted)” in the table below to present the prior year amounts on a split-adjusted basis. Additionally, the formula for distributing available cash among our General Partner and limited partners was revised to reflect this unit split, as set forth in our partnership agreement, as amended, and is presented below.

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 allocate our net income among our General Partner and limited partners using the two-class method in accordance with applicable authoritative accounting guidance. Under the two-class method, we allocate our net income, including any incentive distribution rights, or IDRs, 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 based on their sharing of losses of 2 percent and 98 percent, respectively, as set forth in our partnership agreement.

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

	For the three month period ended March 31,	
	2012	2011
	(in millions, except per unit amounts)	
Net income	$ 112.0	$ 131.8
Less: Net income attributable to noncontrolling interest	13.0	14.7
Net income attributable to general and limited partner interests in Enbridge Energy Partners, L.P.	99.0	117.1
Less distributions paid:		
Incentive distributions to our General Partner	(25.9)	(18.4)
Distributed earnings allocated to our General Partner	(3.0)	(2.7)
Total distributed earnings to our General Partner	(28.9)	(21.1)
Total distributed earnings to our limited partners	(151.8)	(130.9)
Total distributed earnings	(180.7)	(152.0)
Overdistributed earnings	$ (81.7)	$ (34.9)
Weighted average limited partner units outstanding	284.7	252.8
Basic and diluted earnings per unit:		
Distributed earnings per limited partner unit [(1)]	$ 0.53	$ 0.52
Overdistributed earnings per limited partner unit [(2)]	(0.28)	(0.14)
Net income per limited partner unit (basic and diluted)	$ 0.25	$ 0.38

(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 percent) of distributions in excess of earnings divided by the weighted average number of limited partner interests outstanding for the period and under distributed earnings allocated to the limited partners based on the distribution waterfall that is outlined in our partnership agreement.

3. CASH AND CASH EQUIVALENTS

We extinguish liabilities when a creditor has relieved us of our obligation, which occurs when our financial institution honors a check that the creditor has presented for payment. Accordingly, obligations for which we have made payments that have not yet been presented to the financial institution totaling approximately $24.7 million at March 31, 2012 and $30.8 million at December 31, 2011 are included in "Accounts payable and other" on our consolidated statements of financial position.

4. INVENTORY

	March 31, 2012	December 31, 2011
	(in millions)	
Materials and supplies	$ 2.1	$ 2.2
Crude oil inventory	24.9	10.7
Natural gas and NGL inventory	49.7	80.7
	$76.7	$93.6

The "Cost of natural gas" on our consolidated statements of income includes charges totaling $2.4 million for the three month period ended March 31, 2012 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. Similar charges to reduce our natural gas and NGLs inventories were not incurred for the three month period ended March 31, 2011.

5. PROPERTY, PLANT AND EQUIPMENT

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

	March 31, 2012	December 31, 2011 [(1)]
	(in millions)	
Land	$ 38.5	$ 37.1
Rights-of-way	574.2	564.4
Pipelines	6,261.7	6,268.1
Pumping equipment, buildings and tanks	1,486.4	1,436.3
Compressors, meters and other operating equipment	1,639.1	1,623.2
Vehicles, office furniture and equipment	215.6	211.8
Processing and treating plants	461.7	456.6
Construction in progress	1,056.3	874.3
Total property, plant and equipment	11,733.5	11,471.8
Accumulated depreciation	(2,112.4)	(2,032.4)
Property, plant and equipment, net	$ 9,621.1	$ 9,439.4

(1) For comparability purposes, we have made reclassifications of approximately $63.6 million out of the Processing and treating plants category and into the Land, Pumping equipment, buildings and tanks, and Compressors, meters and other operating equipment categories for the December 31, 2011 balances.

Based on our own internal study, with consideration of a third-party consultant's report, revised depreciation rates for our Anadarko, North Texas and East Texas natural gas systems were implemented effective July 1, 2011. The average remaining service life of these natural gas systems was extended from 29 years to 36 years. The predominant factor contributing to the change in service lives was an increase in the estimated remaining reserves in the regions our natural gas systems serve, due to enhancements in fracturing technologies which will allow producers to have greater access to unconventional gas. The new remaining service lives will result in an approximately $34 million annual reduction in depreciation expense in future years, with a reduction of $8.5 million for the current quarter ended March 31, 2012.

6. DEBT

Credit Facility

In September 2011, we entered into a new credit agreement with Bank of America, as administrative agent, and the lenders party thereto, which we refer to as the New Credit Facility. The new agreement is a committed senior unsecured revolving credit facility that permits aggregate borrowings of up to, at any one time outstanding, $2 billion, a letter of credit subfacility and a swing line subfacility with a maturity date of September 26, 2016.

Effective September 30, 2011, our New Credit Facility was amended to further modify the definition of Consolidated Earnings Before Income Taxes Depreciation and Amortization, or Consolidated EBITDA, as set forth in the terms of our New Credit Facility, to increase from $550 million to $650 million, the aggregate amount of the costs associated with the crude oil releases on Lines 6A and 6B that are excluded from the computation of Consolidated EBITDA. Specifically, the costs allowed to be excluded from Consolidated EBITDA are those for emergency response, environmental remediation, cleanup activities, costs to repair the pipelines, inspection costs, potential claims by third parties and lost revenue. At March 31, 2012 we were in compliance with the terms of our financial covenants.

The amounts we may borrow under the terms of our New Credit Facility are reduced by the face amount of our letters of credit outstanding. Our current policy is to maintain availability at any time under our New Credit Facility 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, 2012, we could borrow $1,526.1 million under the terms of our New Credit Facility, determined as follows:

	(in millions)
Total credit available under New Credit Facility	$2,000.0
Less: Amounts outstanding under New Credit Facility	—
Principal amount of commercial paper outstanding	325.0
Letters of credit outstanding	148.9
Total amount we could borrow at March 31, 2012	$1,526.1

Individual London Inter-Bank Offered Rate, or LIBOR rate, borrowings under the terms of our New Credit Facility 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 New Credit Facility and do not require any cash repayments or prepayments. For the three month periods ended March 31, 2012 and 2011 we have not renewed any LIBOR rate borrowings or base rate borrowings, on a non-cash basis.

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 that is supported by our New Credit Facility. 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 New Credit Facility. At March 31, 2012, we had $325.0 million of commercial paper outstanding at a weighted average interest rate of 0.45%, excluding the effect of our interest rate hedging activities. At December 31, 2011, we had $275.0 million of commercial paper outstanding at a weighted average interest rate of 0.44%, 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 New Credit Facility.

We have the ability and intent to refinance all of our commercial paper obligations on a long-term basis through borrowings under our New Credit Facility. Accordingly, such amounts have been classified as "Long-term debt" in our accompanying consolidated statements of financial position.

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 New Credit Facility and prior credit facilities approximate their fair values at March 31, 2012 and December 31, 2011, 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 New Credit Facility 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, 2012		December 31, 2011	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(in millions)			
Commercial Paper	$ 325.0	$ 325.0	$ 275.0	$ 275.0
7.900% Senior Notes due 2012	100.0	104.5	100.0	106.1
4.750% Senior Notes due 2013	200.0	208.6	199.9	209.6
5.350% Senior Notes due 2014	200.0	218.8	200.0	218.9
5.875% Senior Notes due 2016	299.9	346.9	299.9	346.2
7.000% Senior Notes due 2018	99.9	124.0	99.9	123.8
6.500% Senior Notes due 2018	398.7	482.6	398.7	481.5
9.875% Senior Notes due 2019	500.0	713.0	500.0	715.1
5.200% Senior Notes due 2020	499.8	564.5	499.8	563.0
4.200% Senior Notes due 2021	598.9	623.2	598.8	620.8
7.125% Senior Notes due 2028	99.8	133.6	99.8	134.6
5.950% Senior Notes due 2033	199.7	235.0	199.7	238.1
6.300% Senior Notes due 2034	99.8	121.7	99.8	123.5
7.500% Senior Notes due 2038	399.0	553.0	399.0	563.5
5.500% Senior Notes due 2040	546.2	580.7	546.2	594.7
8.050% Junior subordinated notes due 2067	399.6	448.1	399.6	435.5
Total	$4,966.3	$5,783.2	$4,916.1	$5,749.9

7. PARTNERS' CAPITAL

Split of Partnership Units

Effective April 21, 2011, the board of directors of Enbridge Management, as delegate of our General Partner, approved a two-for-one split of our common units and i-units outstanding to unitholders of record on April 7, 2011. The net income per share and weighted average shares outstanding for the three month period ended March 31, 2011 presented in our consolidated statements of income are presented reflecting the retroactive effects of the share split.

Distribution to Partners

The following table sets forth our distributions, as approved by the board of directors of Enbridge Management, during the three month period ended March 31, 2012.

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, 2012	February 7, 2012	February 14, 2012	$0.5325	$180.3	$20.5	$0.4	$159.4

(1) We issued 601,828 i-units to Enbridge Management, the sole owner of our i-units, during 2012 in lieu of cash distributions.
(2) We retained an amount equal to two percent of the i-unit distribution from our General Partner to maintain its two percent 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, 2012 and 2011. The noncontrolling interest in the OLP arises from the joint funding arrangement with our General Partner and its affiliate to finance 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.

	For the three month periods ended March 31,	
	2012	**2011**
	(in millions)	
General and limited partner interests		
Beginning balance	$4,483.1	$3,541.8
Proceeds from issuance of partnership interests, net of costs	—	58.7
Net income	99.0	117.1
Distributions	(159.4)	(132.0)
Ending balance	$4,422.7	$3,585.6
Accumulated other comprehensive income (loss)		
Beginning balance	$ (316.5)	$ (121.7)
Net realized losses on changes in fair value of derivative financial instruments reclassified to earnings	13.8	18.8
Unrealized net gain (loss) on derivative financial instruments	21.6	(76.2)
Ending balance	$ (281.1)	$ (179.1)
Noncontrolling interest		
Beginning balance	$ 445.5	$ 465.4
Capital contributions	—	3.2
Comprehensive income:		
Net income	13.0	14.7
Distributions to noncontrolling interest	(15.8)	(21.8)
Ending balance	$ 442.7	$ 461.5
Total partners' capital at end of period	$4,584.3	$3,868.0

8. RELATED PARTY TRANSACTIONS

Joint Funding Arrangement for Alberta Clipper Pipeline

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 Inc., or 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, 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, at which time we also terminated the A1 Credit Agreement. The promissory note payable, which we refer to as 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 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. 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, 2012 and 2011 are as follows:

	A1 Term Note March 31,	
	2012	2011
	(in millions)	
Beginning Balance	$342.0	$347.4
Borrowings	—	2.6
Repayments	(6.0)	—
Ending Balance	$336.0	$350.0

Our General Partner also made equity contributions totaling $3.2 million to the OLP during the three month period ended March 31, 2011 to fund its equity portion of the construction costs associated with the Alberta Clipper Pipeline. No such contributions were made during the three month period ended March 31, 2012.

We allocated earnings derived from operating the Alberta Clipper Pipeline in the amount of $13.0 million to our General Partner for its 66.67 percent share of the earnings of the Alberta Clipper Pipeline for the three month period ended March 31, 2012. We allocated $14.7 million for the same three month period ended March 31, 2011. 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, 2012, 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, 2012	February 14, 2012	$7.9	$15.8	$23.7
		$7.9	$15.8	$23.7

9. COMMITMENTS AND CONTINGENCIES

Environmental Liabilities

We are subject to federal and state laws and regulations relating to the protection of the environment. Environmental risk is inherent to liquid hydrocarbon and natural gas pipeline operations, and we could, at times, be 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, 2012 and December 31, 2011, we had $20.9 million and $31.3 million, respectively, included in "Other long-term liabilities," that we have accrued for costs we have incurred primarily to address remediation of contaminated sites, asbestos containing materials, management of hazardous waste material disposal, outstanding air quality measures for certain of our liquids and natural gas assets and penalties we have been or expect to be assessed.

Lakehead Lines 6A & 6B Crude Oil Releases

Line 6B Crude Oil Release

We continue to make progress on the cleanup, remediation and restoration of the areas affected by the Line 6B crude oil release. We expect to make payments for additional costs associated with extended submerged oil recovery operations including reassessment, remediation and restoration of the area and air and groundwater monitoring, scientific studies and hydrodynamic modeling, along with legal, professional and regulatory costs through future periods. All the initiatives we will undertake in the monitoring and restoration phase are intended to restore the crude oil release area to the satisfaction of the appropriate regulatory authorities.

The total cost estimate remains at approximately $765 million for this incident at March 31, 2012 based on a review of costs and commitments incurred coupled with our evaluation of additional information regarding requirements for environmental restoration and remediation. 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, 2012. Our estimates do not include amounts we have capitalized or any fines, penalties or claims associated with the release that may later become evident and is before any insurance recoveries. 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	$365
Environmental Consultants	148
Professional, regulatory and other	252
Total	$765

We expect that we will have paid approximately 95 percent of the estimated costs associated with this crude oil release at the end of 2012. We have made payments totaling $620.9 million for costs associated with the Line 6B crude oil release, $50.7 million of which relates to the three month period ended March 31, 2012. We have a remaining liability of $144.1 million, a majority of which is presented as current, on our consolidated statement of financial position at March 31, 2012.

Line 6A Crude Oil Release

We are continuing to monitor the areas affected by the crude oil release from Line 6A of our Lakehead system for any additional requirements. We have substantially completed the cleanup, remediation and restoration of the areas affected by the release.

In connection with this crude oil release, the cost estimate remains at approximately $48 million, before insurance recoveries and excluding fines and penalties. We continue to monitor this estimate based upon actual invoices received and paid for the personnel, equipment and services provided by our vendors and currently available facts specific to these circumstances, existing technology and presently enacted laws and regulations to determine if our estimate should be updated. We have made payments totaling $45.9 million for costs associated with the Line 6A crude oil release, $0.5 million of which relates to the three month period ended March 31, 2012. We have a remaining total liability of $2.1 million, a majority of which is presented as current, on our consolidated statement of financial position as of March 31, 2012.

We have the potential of incurring additional costs in connection with this crude oil release, including fines and penalties as well as expenditures associated with litigation. 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.

Lines 6A & 6B Fines and Penalties

Our estimated environmental costs for both the Line 6A and Line 6B crude oil releases do not include an estimate for fines and penalties at March 31, 2012, which may be imposed by the EPA and Pipeline and Hazardous Materials Safety Administration, or PHMSA, in addition to other federal, state and local governmental agencies. Several factors remain outstanding at the end of the period that we consider critical in estimating the amount of fines and penalties that we may be assessed.

Due to the absence of sufficient information, we cannot provide a reasonable estimate of our liability for fines and penalties that we could be assessed in connection with each of the releases. As a result, we have not recorded any liability for expected fines and penalties.

Insurance Recoveries

We are included in the comprehensive insurance program that is maintained by Enbridge for its subsidiaries and affiliates, which renews May of each year. The program 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. The claims 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. Based on our remediation spending through March 31, 2012, we have exceeded the limits of coverage under this insurance policy. 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.

In the first quarter of 2012, we received payments of $50.0 million for insurance receivable claims we previously recognized as a reduction to environmental costs in 2011. As of March 31, 2012, we have collected total insurance recoveries of $335.0 million for the Line 6B crude oil release. We expect to record a receivable 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 the first quarter of 2011, we recognized insurance recoveries of $35.0 million as a reduction to environmental costs, for claims we filed, while we recognized no such recoveries during the first quarter of 2012.

Enbridge's current comprehensive insurance program, expiring April 30, 2012 has a current liability aggregate limit of $575.0 million, including pollution liability. Enbridge will renew its liability insurance and expects to increase the aggregate limit of coverage effective May 1, 2012 through April 30, 2013.

Line 6B Pipeline Integrity Plan

In connection with the restart of Line 6B of our Lakehead system, we committed to accelerate a process we had initiated prior to the crude oil release to perform additional inspections, testing and refurbishment of Line 6B within and beyond the immediate area of the July 26, 2010 crude oil release. Pursuant to this agreement with PHMSA, we completed remediation of those pipeline anomalies identified by us between the years 2007 and 2009 that were scheduled for refurbishment and anomalies identified for action in a July 2010 PHMSA notification on schedule, within 180 days of the September 27, 2010 restart of Line 6B, as required. In addition to the required integrity measures, we also agreed to replace a 3,600 foot section of the Line 6B pipeline that lies underneath the St. Clair River in Michigan within one year of the restart of Line 6B, subject to obtaining required permits. A new line was installed beneath the St. Clair River in March 2011 and was tied into Line 6B during June 2011.

We filed a supplement to our Facilities Surcharge Mechanism, or FSM, which became effective on April 1, 2011 when it was approved by the FERC for recovery of $175 million of capital costs and $5 million of operating costs for the 2010 and 2011 Line 6B Pipeline Integrity Plan. The costs associated with the Line 6B Pipeline Integrity Plan, which include an equity return component, interest expense and an allowance for income taxes will be recovered over a 30-year period, while operating costs will be recovered through our annual tolls for actual costs incurred. These costs include costs associated with the PHMSA Corrective Action Order and other required integrity work.

Line Replacement Program

On May 12, 2011, we announced plans to replace 75-miles of non-contiguous sections of Line 6B of our Lakehead system at an estimated cost of $286 million. Our Line 6B pipeline runs from Griffith, Indiana through Michigan to the international border at the St. Clair River. Subject to regulatory approvals, the new segments of pipeline will be constructed mostly in 2012 and are targeted to be placed in-service by the first quarter of 2013 in consultation with, and to minimize impact to, refiners and shippers served by Line 6B crude oil deliveries. These costs will be recovered through our FSM that is part of the system-wide rates of the Lakehead system. We have subsequently revised the scope of this project to increase the cost by approximately $30 million, which will bring the total capital for this replacement program to an estimated cost of $316 million. The $30 million of additional costs do not currently have recovery under our FSM.

The total cost of these integrity measures is separate from the environmental liabilities discussed above. The pipeline integrity and replacement costs will be capitalized or expensed in accordance with our capitalization policies as these costs are incurred, the majority of which are expected to be capital in nature.

Proceeds from Claim Settlements

In April 2011, we recorded proceeds of $11.6 million for settlement of claims we made for payment from unrelated parties in connection with operational matters that occurred in the normal course of business. We recorded $5.6 million as a reduction to "Operating and administrative" expenses of our Liquids segment and $6.0 million as "Other income" in our consolidated statements of income for the three month period ended March 31, 2011.

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 6A and Line 6B crude oil releases. Approximately twenty-five actions or claims have been filed 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 these actions to be material. With respect to the Line 6B crude oil release, no penalties or fines have been assessed against us as of March 31, 2012.

Governmental agencies and regulators have also initiated investigations into the Line 6A crude oil release. One claim has been filed against us and our affiliates by the State of Illinois in 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 associated with the Line 6A and Line 6B crude oil releases as described above in the section titled *Lakehead Lines 6A & 6B Crude Oil Releases* of this footnote.

10. DERIVATIVE FINANCIAL INSTRUMENTS AND HEDGING ACTIVITIES

Our net income and cash flows are subject to volatility stemming from changes in interest rates on our variable rate debt obligations and fluctuations in commodity prices of natural gas, NGLs, condensate, crude oil and fractionation margins. Fractionation margins represent the relative difference between the price we receive from NGL 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 to our cash flows. Based on our risk management policies, all of our derivative financial instruments are employed in connection with an underlying asset, liability and/or forecasted transaction and are not entered into with the objective of speculating on interest rates or commodity prices. We have hedged a portion of our exposure to variability in future cash flows associated with the risks discussed above through 2017 in accordance with our risk management policies.

Accounting Treatment

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 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 hedge, or is not designated as a 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,” 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 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 and interest rate 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 Marketing 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 Marketing 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.
- **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. In the second quarter 2009, we determined that a sub-group of physical NGL sales contracts with terms allowing for economic net settlement did not qualify for the NPNS scope exception and are being marked-to-market each period with the changes in fair value recorded in earnings. The forward contracts for which we have revoked the NPNS election do not qualify for hedge accounting 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 Marketing segment, we use forward contracts to sell natural gas to our customers. Historically, we have not considered these contracts to be derivatives under the NPNS exception allowed by authoritative accounting guidance. In the first quarter of 2010, we determined that a sub-group of physical natural gas sales contracts with terms allowing for economic net settlement did 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.

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.

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:

- Natural Gas and Marketing segments commodity-based derivatives—"Cost of natural gas"
- Liquids segment commodity-based derivatives—"Operating revenue" and "Power"
- 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 unrealized gains and losses associated with the changes in fair value of our derivative financial instruments:

	For the three month period ended March 31,	
	2012	2011
	(unaudited; in millions)	
Liquids segment		
Non-qualified hedges	$(8.8)	$ (4.6)
Natural Gas segment		
Hedge ineffectiveness	(1.8)	1.2
Non-qualified hedges	5.5	(10.3)
Marketing		
Non-qualified hedges	(1.8)	(2.9)
Commodity derivative fair value net losses	(6.9)	(16.6)
Corporate		
Non-qualified interest rate hedges	—	(0.1)
Derivative fair value net losses	$(6.9)	$(16.7)

Derivative Positions

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

	March 31, 2012	December 31, 2011
	(in millions)	
Other current assets	$ 24.1	$ 20.2
Other assets, net	4.7	13.0
Accounts payable and other	(157.0)	(166.2)
Other long-term liabilities	(98.7)	(121.5)
	$(226.9)	$(254.5)

The changes in the net 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 long-term 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 $46.9 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, 2012, unrealized commodity hedge losses of $5.2 million were de-designated as a result of the hedges no longer meeting hedge accounting criteria. We estimate that approximately $153.2 million, representing unrealized net losses from our cash flow hedging activities based on pricing and positions at March 31, 2012, will be reclassified from AOCI to earnings during the next 12 months.

In connection with our September 2011 issuance of the 2021 Notes, we paid $18.8 million to settle treasury locks we entered to hedge the interest payments on a portion of these obligations through the maturity date of the 2021 Notes. The settlement amount is being amortized from AOCI to "Interest expense" over the respective 10-year term of the 2021 Notes.

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

	March 31, 2012	December 31, 2011
	(in millions)	
Counterparty Credit Quality*		
AAA	$ 0.9	$ (0.2)
AA	(79.9)	(98.4)
A	(152.6)	(160.7)
Lower than A	4.7	4.8
	$(226.9)	$(254.5)

* As determined by nationally-recognized statistical ratings organizations.

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 declined. When credit thresholds are met pursuant to the terms of our International Securities Dealers Association, or ISDA®, financial contracts, we have the right to require collateral from our counterparties. We have included any cash collateral received in the balances listed above. When we are in a position of posting collateral to cover our counterparties' exposure to our non-performance, the collateral is provided through letters of credit, which are not reflected above.

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, 2012, we would have been required to provide additional letters of credit in the amount of $53.1 million.

At March 31, 2012 and December 31, 2011, we had credit concentrations in the following industry sectors, as presented below:

	March 31, 2012	December 31, 2011
	(in millions)	
United States financial institutions and investment banking entities	$(145.8)	$(163.6)
Non-United States financial institutions	(83.7)	(88.7)
Other	2.6	(2.2)
	$(226.9)	$(254.5)

We are holding no cash collateral on our asset exposures, and we have provided letters of credit totaling $148.3 million and $173.2 million relating to our liability exposures pursuant to the margin thresholds in effect at March 31, 2012 and December 31, 2011, 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. A reconciliation between the derivative balances presented at gross values rather than the net amounts we present in our other derivative disclosures, is also provided below.

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, 2012	December 31, 2011	Financial Position Location	March 31, 2012	December 31, 2011
			(in millions)			
Derivatives designated as hedging instruments [1]						
Interest rate contracts	Other current assets	$ —	$ —	Accounts payable and other	$(126.5)	$(134.1)
Interest rate contracts	Other assets, net	—	0.2	Other long-term liabilities	(73.2)	(109.4)
Commodity contracts	Other current assets	10.9	6.4	Accounts payable and other	(29.3)	(30.5)
Commodity contracts	Other assets, net	9.1	11.4	Other long-term liabilities	(36.4)	(25.9)
		20.0	18.0		(265.4)	(299.9)
Derivatives not designated as hedging instruments						
Interest rate contracts	Other current assets	3.7	4.8	Accounts payable and other	(3.4)	(4.4)
Interest rate contracts	Other assets, net	2.7	2.5	Other long-term liabilities	(2.4)	(2.3)
Commodity contracts	Other current assets	35.3	31.7	Accounts payable and other	(23.5)	(19.9)
Commodity contracts	Other assets, net	8.6	16.4	Other long-term liabilities	(2.5)	(1.4)
		50.3	55.4		(31.8)	(28.0)
Total derivative instruments		$70.3	$73.4		$(297.2)	$(327.9)

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

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, 2012					
Interest rate contracts	$ 43.6	Interest expense	$ (7.2)	Interest expense	$ 0.1
Commodity contracts	(3.9)	Cost of natural gas	(6.6)	Cost of natural gas	(1.9)
Total	$ 39.7		$(13.8)		$(1.8)
For the three month period ended March 31, 2011					
Interest rate contracts	$ 16.3	Interest expense	$ (6.9)	Interest expense	$—
Commodity contracts	(73.9)	Cost of natural gas	(11.9)	Cost of natural gas	1.2
Total	$(57.6)		$(18.8)		$ 1.2

(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.

Effect of Derivative Instruments on Consolidated Statements of Income

		For the three month period ended March 31,	
		2012	2011
Derivatives Not Designated as Hedging Instruments	Location of Gain or (Loss) Recognized in Earnings	Amount of Gain or (Loss) Recognized in Earnings[1]	
		(in millions)	
Interest rate contracts	Interest expense	$—	$ (0.1)
Commodity contracts	Operating revenue	(8.5)	(4.5)
Commodity contracts	Power	(0.3)	(0.1)
Commodity contracts	Cost of natural gas	3.7	(13.2)
Total		$(5.1)	$(17.9)

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

Gross to Net Presentation Reconciliation of Derivative Assets and Liabilities

	March 31, 2012			December 31, 2011		
	Assets	Liabilities	Total	Assets	Liabilities	Total
			(in millions)			
Fair value of derivatives—gross presentation	$ 70.3	$(297.2)	$(226.9)	$ 73.4	$(327.9)	$(254.5)
Effects of netting agreements	(41.5)	41.5	—	(40.2)	40.2	—
Fair value of derivatives—net presentation	$ 28.8	$(255.7)	$(226.9)	$ 33.2	$(287.7)	$(254.5)

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, 2012 and December 31, 2011. We classify financial assets and liabilities in their entirety based on the lowest level of input that is significant to the fair value measurement. Our assessment of the significance of a particular input to the fair value measurement requires judgment and may affect our valuation of the financial assets and liabilities and their placement within the fair value hierarchy.

	March 31, 2012				December 31, 2011			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
	(in millions)							
Interest rate contracts	$—	$(199.0)	$ —	$(199.0)	$—	$(242.6)	$ —	$(242.6)
Commodity contracts:								
Financial	—	(35.2)	(13.2)	(48.4)	—	(10.2)	(15.9)	(26.1)
Physical	—	—	8.3	8.3	—	—	4.2	4.2
Commodity options	—	—	12.2	12.2	—	—	10.0	10.0
Total	$—	$(234.2)	$ 7.3	$(226.9)	$—	$(252.8)	$ (1.7)	$(254.5)

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, NGL's, 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 decrease the fair value of the positions.

Quantitative Information About Level 3 Fair Value Measurements

				Range [1]			
Contract Type	Fair Value at March 31, 2012 [2]	Valuation Technique	Unobservable Input	Lowest	Highest	Weighted Average	Units
			(in millions)				
Commodity Contracts - Financial							
Natural Gas	$ 8.7	Market Approach	Forward Gas Price	1.94	4.32	2.77	MMBtu
Crude Oil	$ 0.5	Market Approach	Forward Crude Price	70.23	126.22	117.72	Bbl
NGLs	$(22.4)	Market Approach	Forward NGL Price	0.19	2.38	1.51	Gal
Commodity Contracts - Physical							
Natural Gas	$ 1.7	Market Approach	Forward Gas Price	1.94	4.64	2.84	MMBtu
Crude Oil	$ 2.4	Market Approach	Forward Crude Price	83.18	124.89	104.34	Bbl
NGLs	$ 5.9	Market Approach	Forward NGL Price	0.11	2.78	1.13	Gal
Power	$ (1.7)	Market Approach	Forward Power Price	23.04	37.61	32.07	MWh
Commodity Options							
Natural Gas, Crude and NGLs	$ 12.2	Option Model	Option Volatility	26%	62%	37%	

(1) Prices are in $/MMBtu for Natural Gas, $/Gallons, or Gal, for NGLs, $/barrels, or Bbl, for Crude Oil and $/Megawatt hours, or MWh, for Power.

(2) Fair values are presented in millions of dollars and include credit valuation adjustments of approximately $0.2 million of losses.

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, 2012 to March 31, 2012. 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, 2012	$(15.9)	$ 4.2	$10.0	$(1.7)
Transfer out of Level 3 [1]	—	—	—	—
Gains or losses				
Included in earnings (or changes in net assets)	(3.9)	8.6	3.5	8.2
Included in other comprehensive income	4.6	—	(0.3)	4.3
Purchases, issuances, sales and settlements				
Purchases	—	—	—	—
Settlements [2]	2.0	(4.5)	(1.0)	(3.5)
Ending balance as March 31, 2012	$(13.2)	$ 8.3	$12.2	$ 7.3
Amount of changes in net assets attributable to the change in unrealized gains or losses related to assets still held at the reporting date	$ (2.6)	$ 5.8	$ 2.9	$ 6.1
Amounts reported in operating revenue	$ 1.2	$—	$ —	$ 1.2

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

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

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, 2012 and December 31, 2011.

	At March 31, 2012						At December 31, 2011	
			Wtd. Average Price [2]		Fair Value [3]		Fair Value [3]	
	Commodity	Notional [1]	Receive	Pay	Asset	Liability	Asset	Liability
Portion of contracts maturing in 2012								
Swaps								
Receive variable/pay fixed	Natural Gas	1,192,669	$ 2.40	$ 6.57	$—	$ (5.0)	$—	$ (8.1)
	NGL	273,750	$ 75.19	$ 79.34	$—	$ (1.1)	$ 0.4	$ —
	Crude Oil	180,000	$104.19	$107.00	$—	$ (0.5)	$—	$ —
Receive fixed/pay variable	Natural Gas	1,871,196	$ 4.75	$ 2.55	$ 4.1	$ —	$ 7.1	$ —
	NGL	2,414,998	$ 52.38	$ 55.02	$ 8.6	$(15.0)	$ 6.3	$(20.6)
	Crude Oil	1,556,525	$ 95.01	$104.34	$ 2.4	$(16.9)	$ 3.5	$(15.6)
Receive variable/pay variable	Natural Gas	68,445,731	$ 2.37	$ 2.36	$ 1.7	$ (0.8)	$ 2.8	$ (0.8)
Physical Contracts								
Receive variable/pay fixed	NGL	35,000	$ 52.31	$ 55.22	$—	$ (0.1)	$ 0.3	$ —
	Crude Oil	325,000	$103.44	$105.53	$—	$ (0.7)	$ 0.2	$ (0.3)
Receive fixed/pay variable	NGL	135,000	$ 46.67	$ 45.57	$ 0.2	$ —	$ 0.3	$ (1.0)
	Crude Oil	443,000	$105.07	$103.70	$ 0.7	$ (0.1)	$ 0.1	$ (0.6)
Receive variable/pay variable	Natural Gas	30,804,505	$ 2.42	$ 2.39	$ 1.0	$ (0.1)	$ 1.2	$ —
	NGL	9,422,657	$ 47.28	$ 46.73	$ 6.9	$ (1.6)	$ 8.8	$ (3.8)
	Crude Oil	1,574,270	$105.53	$103.76	$ 7.5	$ (4.7)	$ 1.5	$ (1.9)
Pay fixed	Power [4]	46,285	$ 27.24	$ 40.28	$—	$ (0.6)	$—	$ (0.5)
Portion of contracts maturing in 2013								
Swaps								
Receive variable/pay fixed	Natural Gas	96,846	$ 3.38	$ 5.11	$—	$ (0.2)	$—	$ (0.1)
Receive fixed/pay variable	Natural Gas	4,488,100	$ 5.11	$ 3.30	$ 8.1	$ —	$ 5.9	$ —
	NGL	1,308,010	$ 58.83	$ 67.64	$ 2.2	$(13.7)	$ 0.5	$ (8.7)
	Crude Oil	1,430,435	$ 92.11	$103.59	$ 1.6	$(17.9)	$ 3.7	$(10.0)
Receive variable/pay variable	Natural Gas	34,670,000	$ 3.40	$ 3.38	$ 0.8	$ (0.1)	$ 0.8	$ (0.1)
Physical Contracts								
Receive variable/pay variable	Natural Gas	11,599,382	$ 3.43	$ 3.39	$ 0.5	$ —	$ 0.5	$ —
	NGL	321,071	$ 60.28	$ 59.12	$ 0.4	$ —	$ 0.4	$ (0.1)
Pay fixed	Power [4]	42,924	$ 32.77	$ 42.82	$—	$ (0.4)	$—	$ (0.3)
Portion of contracts maturing in 2014								
Swaps								
Receive variable/pay fixed	Natural Gas	21,870	$ 3.88	$ 5.22	$—	$ —	$—	$ —
Receive fixed/pay variable	NGL	381,425	$ 77.58	$ 86.90	$—	$ (3.5)	$ 0.8	$ (1.9)
	Crude Oil	1,228,955	$ 94.27	$ 98.88	$ 1.5	$ (7.1)	$ 4.9	$ (3.1)
Receive variable/pay variable	Natural Gas	6,300,000	$ 3.92	$ 3.91	$ 0.1	$ —	$ 0.1	$ —
Physical Contracts								
Receive variable/pay variable	Natural Gas	1,115,075	$ 4.03	$ 3.90	$ 0.1	$ —	$ 0.1	$ —
Pay fixed	Power [4]	58,608	$ 35.37	$ 46.58	$—	$ (0.6)	$—	$ (0.5)
Portion of contracts maturing in 2015								
Swaps								
Receive fixed/pay variable	NGL	109,500	$ 88.36	$ 92.99	$ 0.1	$ (0.6)	$ 0.7	$ (0.2)
	Crude Oil	865,415	$ 97.72	$ 95.15	$ 3.4	$ (1.3)	$ 6.0	$ (0.4)
Physical Contracts								
Receive variable/pay variable	Natural Gas	1,115,075	$ 4.38	$ 4.26	$ 0.1	$ —	$ 0.1	$ —
Portion of contracts maturing in 2016								
Swaps								
Receive fixed/pay variable	Crude Oil	45,750	$ 99.31	$ 93.06	$ 0.3	$ —	$ 0.4	$ —
Physical Contracts								
Receive variable/pay variable	Natural Gas	745,420	$ 4.64	$ 4.51	$ 0.1	$ —	$ 0.1	$ —

(1) Volumes of natural gas are measured in millions of British Thermal Units, or MMBtu, whereas volumes of NGL and crude oil are measured in barrels, or Bbl. Our power purchase agreements are measured in Megawatt hours, or 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, 2012 and December 31, 2011, 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 and $0.8 million of losses at March 31, 2012 and December 31, 2011, respectively.

(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, 2012 and December 31, 2011.

	At March 31, 2012						At December 31, 2011	
					Fair Value [3]		Fair Value [3]	
	Commodity	Notional [1]	Strike Price [2]	Market Price [2]	Asset	Liability	Asset	Liability
Portion of option contracts maturing in 2012								
Puts (purchased)	NGL	1,221,450	$42.36	$ 40.12	$8.6	$—	$7.3	$—
	Crude Oil	48,125	$99.00	$104.54	$0.3	$—	$0.7	$—
Portion of option contracts maturing in 2013								
Puts (purchased)	Natural Gas	1,642,500	$ 4.18	$ 3.30	$1.7	$—	$1.2	$—
	NGL	183,250	$26.25	$ 17.91	$1.7	$—	$0.9	$—

(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, 2012 and December 31, 2011, 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 losses at March 31, 2012 and $0.1 million of losses at December 31, 2011.

Fair Value Measurements of Interest Rate Derivatives

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

Date of Maturity & Contract Type	Accounting Treatment	Notional	Average Fixed Rate [(1)]	Fair Value [(2)] at March 31, 2012	Fair Value [(2)] at December 31, 2011
			(dollars in millions)		
Contracts maturing in 2013					
Interest Rate Swaps—Pay Fixed	Cash Flow Hedge	$800	3.24%	$ (38.3)	$ (42.2)
Interest Rate Swaps—Pay Fixed	Non-qualifying	$125	4.35%	$ (5.9)	$ (6.8)
Interest Rate Swaps—Pay Float	Non-qualifying	$125	4.75%	$ 6.5	$ 7.5
Contracts maturing in 2014					
Interest Rate Swaps—Pay Fixed	Cash Flow Hedge	$200	0.56%	$ —	$ 0.2
Contracts maturing in 2015					
Interest Rate Swaps—Pay Fixed	Cash Flow Hedge	$300	2.43%	$ (4.9)	$ (4.7)
Contracts maturing in 2017					
Interest Rate Swaps—Pay Fixed	Cash Flow Hedge	$500	2.21%	$ (4.9)	$ (5.8)
Contracts settling prior to maturity					
2012—Pre-issuance Hedges	Cash Flow Hedge	$600	4.56%	$(110.4)	$(123.7)
2013—Pre-issuance Hedges	Cash Flow Hedge	$500	3.98%	$ (49.2)	$ (63.1)
2014—Pre-issuance Hedges	Cash Flow Hedge	$750	3.15%	$ 0.9	$ (23.4)

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

(2) The fair value is determined from quoted market prices at March 31, 2012 and December 31, 2011, 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 $7.2 million of gains at March 31, 2012 and $19.4 million of gains at December 31, 2011.

11. INCOME TAXES

We are not a taxable entity for United States federal income tax purposes, or for the majority of states that impose an income tax. Taxes on our net income generally are borne by our unitholders through the allocation of taxable income. Our income tax expense results from the enactment of state income tax laws that apply to entities organized as partnerships by the State of Texas. On May 25, 2011, the Governor of Michigan signed legislation implementing a new corporate income tax system. The new tax system became effective January 1, 2012 and repealed the Michigan Business Tax, or MBT, which imposed tax on individuals, LLCs, trusts, partnerships, S corporations, and C corporations and replaced it with the Michigan Corporate Income Tax, or CIT. The CIT only taxes entities classified as C Corporations, therefore, the Partnership is excluded from the CIT and will no longer pay Michigan income taxes beginning in 2012.

We computed our income tax expense for 2012, by applying a Texas state income tax rate to modified gross margin and for 2011, we applied an additional Michigan state income tax rate to modified gross receipts. The Texas state income tax rate was 0.5% for the three month periods ended March 31, 2012 and 2011. The Michigan state income tax rate was 0.2% for the three month period ended March 31, 2011. Our income tax expense is $2.1 million and $2.3 million for the three month periods ended March 31, 2012 and 2011, respectively.

At March 31, 2012 and December 31, 2011, we have included a current income tax payable of $9.9 million and $7.2 million in "Property and other taxes payable," respectively. In addition, at March 31, 2012 and December 31, 2011, we have included a deferred income tax liability of $2.6 million and $2.8 million, respectively, in "Other long-term liabilities," on our consolidated statements of financial position to reflect the tax associated with the difference between the net basis in assets and liabilities for financial and state tax reporting.

12. SEGMENT INFORMATION

Our business is divided into operating segments, defined as components of the enterprise, about which financial information is available and evaluated regularly by our Chief Operating Decision Maker 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, since each business segment requires different operating strategies. We have segregated our business activities into three distinct operating segments:

- Liquids;
- Natural Gas; and
- Marketing.

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, 2012				
	Liquids	Natural Gas	Marketing	Corporate [1]	Total
			(in millions)		
Total revenue	$ 322.6	$1,387.5	$336.4	$ —	$ 2,046.5
Less: Intersegment revenue	0.3	218.3	8.4	—	227.0
Operating revenue	322.3	1,169.2	328.0	—	1,819.5
Cost of natural gas	—	965.6	331.3	—	1,296.9
Environmental costs, net of recoveries	3.2	—	—	—	3.2
Oil measurement adjustments	(4.3)	—	—	—	(4.3)
Operating and administrative	81.5	117.6	1.7	0.4	201.2
Power	41.2	—	—	—	41.2
Depreciation and amortization	50.5	33.1	—	—	83.6
	172.1	1,116.3	333.0	0.4	1,621.8
Operating income (loss)	150.2	52.9	(5.0)	(0.4)	197.7
Interest expense	—	—	—	83.6	83.6
Income (loss) from continuing operations before income tax expense	150.2	52.9	(5.0)	(84.0)	114.1
Income tax expense	—	—	—	2.1	2.1
Net income (loss)	150.2	52.9	(5.0)	(86.1)	112.0
Less: Net income attributable to the noncontrolling interest	—	—	—	13.0	13.0
Net income (loss) attributable to general and limited partner ownership interests in Enbridge Energy Partners, L.P.	$ 150.2	$ 52.9	$ (5.0)	$ (99.1)	$ 99.0
Total assets	$6,234.7	$4,679.0	$130.0	$204.5	$11,248.2
Capital expenditures (excluding acquisitions)	$ 144.6	$ 114.0	$ —	$ 2.7	$ 261.3

(1) Corporate consists 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.

	As of and for the three month period ended March 31, 2011				
	Liquids	Natural Gas	Marketing	Corporate [(1)]	Total
			(in millions)		
Total revenue	$ 302.2	$1,802.0	$551.1	$ —	$ 2,655.3
Less: Intersegment revenue	0.4	352.3	13.7	—	366.4
Operating revenue	301.8	1,449.7	537.4	—	2,288.9
Cost of natural gas	—	1,293.8	535.7	—	1,829.5
Environmental costs, net of recoveries	(34.2)	(0.4)	—	—	(34.6)
Oil measurement adjustments	(4.6)	—	—	—	(4.6)
Operating and administrative	70.8	93.6	1.6	1.1	167.1
Power	35.6	—	—	—	35.6
Depreciation and amortization	48.5	39.9	—	—	88.4
	116.1	1,426.9	537.3	1.1	2,081.4
Operating income (loss)	185.7	22.8	0.1	(1.1)	207.5
Interest expense	—	—	—	79.4	79.4
Other income	—	—	—	6.0	6.0
Income (loss) from continuing operations before income tax expense	185.7	22.8	0.1	(74.5)	134.1
Income tax expense	—	—	—	2.3	2.3
Net income (loss)	185.7	22.8	0.1	(76.8)	131.8
Less: Net income attributable to the noncontrolling interest	—	—	—	14.7	14.7
Net income (loss) attributable to general and limited partner ownership interests in Enbridge Energy Partners, L.P.	$ 185.7	$ 22.8	$ 0.1	$ (91.5)	$ 117.1
Total assets	$5,656.5	$4,368.6	$200.6	$178.5	$10,404.2
Capital expenditures (excluding acquisitions)	$ 112.6	$ 66.6	$ —	$ 2.4	$ 181.6

(1) Corporate consists 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.

13. REGULATORY MATTERS

Regulatory Accounting

We apply the authoritative accounting provisions applicable to the regulated operations of our Southern Access and Alberta Clipper pipelines. The rates for both the Southern Access and Alberta Clipper pipelines 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 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. 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 2012, we over collected revenue for our Southern Access Pipeline because the actual volumes were higher than the forecast volumes used to calculate the toll surcharge. As a result, for the three month period ended March 31, 2012, we reduced our revenues by $18.5 million on our consolidated statements of income with a corresponding regulatory liability on our consolidated statements of financial position at March 31, 2012 for the differences in these transportation volumes. The amounts will be refunded through our tolls beginning April 2013 when we update our transportation rates to account for the higher than estimated delivered volumes.

For 2011, we over collected revenue for our Southern Access Pipeline because the actual volumes were higher than the forecast volumes used to calculate the toll surcharge. In addition, the actual costs recognized in 2011 were lower than the forecasted costs used to calculate the toll charge. As a result, in 2011 we reduced our revenues for the amounts we over collected and recorded a regulatory liability. We began to amortize this regulatory liability on a straight line basis during 2012 to recognize the amounts we previously over collected. For the three month period ended March 31, 2012, we increased our revenues by $4.1 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, 2012. At March 31, 2012 and December 31, 2011, we had a $15.0 million and $19.1 million in regulatory liabilities, respectively, on our consolidated statements of financial position related to this over collection. We will begin to reimburse these amounts to our customers when we update our transportation rates to account for the higher delivered volumes and lower costs than estimated.

Alberta Clipper Pipeline

For 2012, we have over collected revenue on our Alberta Clipper Pipeline because the actual volumes were higher than the forecast volumes used to calculate the toll surcharge. Offsetting the impact from the difference in volumes were actual costs recognized in 2011 that were higher than the forecasted costs used to calculate the toll charge. As a result, for the three month period ended March 31, 2012, we reduced our revenues by $12.5 million on our consolidated statement of income with a corresponding increase in the regulatory liability on our consolidated statement of financial position at March 31, 2012 for the differences in transportation volumes and costs. We will begin to reimburse these amounts to our customers in April 2013 when we update our transportation rates to account for the higher delivered volumes and higher costs than estimated.

During 2011, we over collected revenue on our Alberta Clipper Pipeline because the actual volumes were higher than forecasted volumes used to calculate the toll charge. For the three month period ended March 31, 2012, we increased our revenues by $5.2 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, 2012. As of March 31, 2012 and December 31, 2011, we had regulatory liabilities of $19.3 million and $24.5 million, respectively, in our consolidated statements of financial position for the difference in costs. The amounts are being refunded to our customers through transportation rates, which became effective in April 2012.

Regulatory Liability for Southern Lights Pipeline In-Service Delay

In December 2006, as part of the regulatory approval process for its pipeline, Enbridge Pipelines (Southern Lights) L.L.C., or Southern Lights, agreed to the request made by the Canadian Association of Petroleum Producers, referred to as CAPP, to delay the in-service date of its pipeline from January 1, 2010 to July 1, 2010. In exchange for Southern Light's postponement of the in-service date of its pipeline, CAPP agreed to reimburse Southern Lights for any carrying costs incurred during this period as a result of the delayed in-service date. The carrying costs were collected by us through the transportation rates charged on our Lakehead system beginning on April 1, 2010. As of March 31, 2012, we had $27.8 million recorded as a regulatory liability on our consolidated statement of financial position for amounts we over collected in connection with the Southern Lights in-service delay. We will reduce the transportation rates we charge the shippers in the future for the additional amounts we collected beginning in the second quarter 2012 when we update the transportation rates on our Lakehead system.

FERC Transportation Tariffs

Effective April 1, 2012, we filed our annual tariff rate adjustment with the FERC to reflect true-ups for the difference between estimated and actual cost and throughput data for the prior year and our projected costs and throughput for 2012 related to our expansion projects. Also included was a supplement to our FSM for recovery of the costs related to the 2010 and 2011 Line 6B Integrity Program, including costs associated with the PHMSA Corrective Action Order and as discussed in Note 9. *Commitments and Contingencies—Pipeline Integrity Plan*. The FSM, which was approved in July 2004, is a component 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 decreased the average transportation rate for crude oil movements from the Canadian border to Chicago, Illinois by approximately $0.22 per barrel, to an average of approximately $1.60 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.

On May 2, 2011, we filed FERC Tariff 45.0.0 to establish International Joint Tariff rates applicable to the transportation of petroleum from all receipt points in western Canada on Enbridge Pipelines Inc., or EPI's, Canadian Mainline system to all delivery points on the Lakehead pipeline system owned by the OLP and delivery points on the Canadian mainline located downstream of the Lakehead system. This tariff filing became effective July 1, 2011.

Effective July 1, 2011, we increased the rates for transportation on our Lakehead, North Dakota and Ozark systems in compliance with the indexed rate ceilings allowed by the FERC. In May 2011, the FERC determined that the annual change in the Producer Price Index for Finished Goods, or PPI-FG, plus 2.65 percent (PPI-FG + 2.65 percent) should be the oil pricing index for the five year period ending July 2016. The index is used to establish rate ceiling levels for oil pipeline rate changes. The increase in rates is due to an increase in the Producer Price Index for Finished Goods as compared with prior periods. For our Lakehead system, indexing applies only to the base rates and does not apply to the SEP II, Terrace and Facilities surcharges, which include the Southern Access Pipeline and Alberta Clipper Project.

Effective December 19, 2011, we modified the terms of our transportation tariff on our Ozark system to implement a lottery process to allocate new shipper capacity if and when the number of new shippers nominating on the system precludes any individual new shipper from being allocated a minimum batch. Additionally, we increased the minimum accepted batch size from 10,000 Bpd to 30,000 Bpd to ensure accurate delivery measurement.

14. SUBSEQUENT EVENTS

Distribution to Partners

On April 30, 2012, the board of directors of Enbridge Management declared a distribution payable to our partners on May 15, 2012. The distribution will be paid to unitholders of record as of May 7, 2012, of our available cash of $180.7 million at March 31, 2012, or $0.53250 per limited partner unit. Of this distribution, $159.4 million will be paid in cash, $20.9 million will be distributed in i-units to our i-unitholder and $0.4 million will be retained from our General Partner in respect of the i-unit distribution to maintain its two percent general partner interest.

Distribution to Series AC Interests

On April 30, 2012, 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, declared a distribution payable to the holders of the Series AC general and limited partner interests. The OLP will pay $16.8 million to the noncontrolling interest in the Series AC, while $8.4 million will be paid to us.

15. SUPPLEMENTAL CASH FLOWS INFORMATION

The following table provides supplemental information for the item labeled "Other" in the "Cash from operating activities" section our consolidated statements of cash flows.

	For the three month period ended March 31,	
	2012	2011
	(in millions)	
Discount accretion	$ 0.1	$ 0.2
Amortization of debt issuance and hedging costs	3.3	4.2
Deferred income taxes	(0.1)	0.1
Allowance for doubtful accounts	—	0.3
Gain on sale of CO2 plant	—	(1.5)
Settlement of claims, net	—	(10.0)
Other	(0.5)	(0.1)
	$ 2.8	$ (6.8)

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

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

RESULTS OF OPERATIONS—OVERVIEW

We provide services to our customers and returns for our unitholders primarily through the following activities:

- Interstate pipeline transportation and storage of crude oil and liquid petroleum;
- Gathering, treating, processing and transportation of natural gas and natural gas liquids, or NGLs, through pipelines and related facilities; and
- Supply, transportation and sales services, including purchasing and selling natural gas and NGLs.

We conduct our business through three business segments: Liquids, Natural Gas and Marketing. These segments are strategic business units established by senior management to facilitate the achievement of our long-term objectives, to aid in resource allocation decisions and to assess operational performance.

The following table reflects our operating income by business segment and corporate charges for each of the three month periods ended March 31, 2012 and 2011.

	For the three month period ended March 31,	
	2012	2011
	(unaudited; in millions)	
Operating Income		
Liquids	$150.2	$185.7
Natural Gas	52.9	22.8
Marketing	(5.0)	0.1
Corporate, operating and administrative	(0.4)	(1.1)
Total Operating Income	197.7	207.5
Interest expense	83.6	79.4
Other income	—	6.0
Income tax expense	2.1	2.3
Net income	112.0	131.8
Less: Net income attributable to noncontrolling interest	13.0	14.7
Net income attributable to general and limited partner ownership interests in Enbridge Energy Partners, L.P.	$ 99.0	$117.1

Contractual arrangements in our Liquids, Natural Gas and Marketing 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 affected the operating income of our Liquids business for the three month period ended March 31, 2012, as compared with the same period of 2011:

- Insurance recoveries of $35.0 million for the three month period ended March 31, 2011, as compared with no such recoveries during the same period in 2012;
- Additional operating and administrative expenses of $10.7 million due to additional workforce related costs associated with the operational, administrative, regulatory and compliance support;
- Additional power costs of $5.6 million due to higher volumes of crude oil transported on our Lakehead system coupled with the additional cost of using drag reducing agents on our North Dakota and Lakehead systems; and
- Higher average daily delivery volumes on all three of our systems when compared to the same period in 2011 resulting in $14.5 million of additional operating revenue.

Natural Gas

The following factors affected the operating income of our Natural Gas business for the three month period ended March 31, 2012, as compared with the same period of 2011:

- $12.8 million increase in unrealized, non-cash, mark-to-market net gains from derivative instruments that do not qualify for hedge accounting treatment under authoritative accounting guidance, as compared with the same period of 2011;
- The results from our natural gas business were unfavorably impacted by approximately $6.6 million due to the downtime associated with a fire at a third-party fractionation facility which resulted in production from our Anadarko system being shut-in for approximately two weeks. Comparatively during the first quarter 2011, adverse weather conditions and plant downtime had an approximate $13 million negative impact to the gross margin.
- $24.0 million increase in operating and administrative costs primarily associated with increases in additional workforce and operational related costs associated with the expansion of our systems and $7.4 million investigation costs related to accounting misstatements at our Trucking and NGL marketing subsidiary;
- $6.8 million decrease in depreciation expense primarily due to a revision in depreciation rates for the Anadarko, North Texas and East Texas systems effective July 1, 2011, which resulted in a decrease of $8.5 million in depreciation expense. This decrease was partially offset with an increase in depreciation associated with additional assets that were put in service during 2011; and
- NGL and natural gas volume growth on our Anadarko and Elk City systems contributed to increased revenues on these systems.

Marketing

Contributing to the operating loss of our Marketing business for the three month period ended March 31, 2012 compared to the same period in 2011, were relatively stable and low natural gas prices during 2012, due to limited opportunities for us to benefit from significant price differentials between market centers. In addition, for the three month period ended March 31, 2012, we recorded $2.0 million of non-cash changes in inventory to reduce the cost basis of our natural gas inventory to net realizable value with no similar charges recorded in the same period in 2011.

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:

- Natural Gas and Marketing segments commodity-based derivatives—"Cost of natural gas"
- Liquids segment commodity-based derivatives—"Operating revenue" and "Power"
- 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 unrealized gains and losses associated with the changes in fair value of our derivative financial instruments:

	For the three month period ended March 31,	
	2012	2011
	(unaudited; in millions)	
Liquids segment		
Non-qualified hedges	$(8.8)	$ (4.6)
Natural Gas segment		
Hedge ineffectiveness	(1.8)	1.2
Non-qualified hedges	5.5	(10.3)
Marketing		
Non-qualified hedges	(1.8)	(2.9)
Commodity derivative fair value net losses	(6.9)	(16.6)
Corporate		
Non-qualified interest rate hedges	—	(0.1)
Derivative fair value net losses	$(6.9)	$(16.7)

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,	
	2012	2011
	(unaudited; in millions)	
Operating Results		
Operating revenues	$322.3	$301.8
Environmental costs, net of recoveries	3.2	(34.2)
Oil measurement adjustments	(4.3)	(4.6)
Operating and administrative	81.5	70.8
Power	41.2	35.6
Depreciation and amortization	50.5	48.5
Operating expenses	172.1	116.1
Operating Income	$150.2	$185.7
Operating Statistics		
Lakehead system:		
United States [(1)]	1,470	1,357
Province of Ontario [(1)]	391	386
Total Lakehead system deliveries [(1)]	1,861	1,743
Barrel miles (billions)	124	114
Average haul (miles)	732	727
Mid-Continent system deliveries [(1)]	236	218
North Dakota system:		
Trunkline	219	171
Gathering	3	4
Total North Dakota system deliveries [(1)]	222	175
Total Liquids Segment Delivery Volumes [(1)]	2,319	2,136

(1) Average barrels per day in thousands.

Three month period ended March 31, 2012 compared with three month period ended March 31, 2011

The operating revenue of our Liquids segment increased for the three month period ended March 31, 2012 when compared with the same period in 2011 mostly due to higher average daily delivery volumes on all three of our systems when compared to the same period in 2011. The overall increase in average delivery volumes on our systems increased operating revenues by approximately $14.5 million for our Liquids segment. The total average daily deliveries from our liquid systems increased approximately nine percent, to 2.319 million barrels per day, or Bpd, for the three month period ended March 31, 2012 from 2.136 million Bpd for the same period in 2011. The increase in average deliveries on our liquids systems was primarily derived from increases of crude oil supplies from conventional sources as well as strong refinery utilization in the Petroleum Administration for Defense District II, or PADD II.

Another contributing factor to the increase in operating revenue was due to transportation rates implemented July 1, 2011, which increased the index rates on all three of our Liquids systems. In May 2011, the FERC determined that the annual change in the Producer Price Index for Finished Goods, or PPI-FG, plus 2.65 percent (PPI-FG+2.65 percent) should be the oil pricing index for the next five years as opposed to PPI-FG, plus 1.30 percent. Approximately $6.2 million of the increase in operating revenue for the quarter ended March 31, 2012 when compared to the same period in 2011 is attributable to the higher transportation rates.

Our transportation tariffs allow our pipelines to deduct an allowance from our customers for the transportation of their crude oil. We recognize revenue for this allowance at the prevailing market price for crude oil. The average prices of crude oil during the quarter ended March 31, 2012 were higher than the average prices for the same period of 2011. For example, the average allowance oil prices for Lakehead increased approximately 16 percent for the quarter ended March 31, 2012, as compared with the same period in 2011. Coupled with the increased liquids volumes, we have experienced an approximate $2.8 million increase in allowance oil revenues.

Offsetting the increase in operating revenue is a $4.0 million increase in unrealized, non-cash, mark-to-market net losses related to derivative financial instruments as compared with the same period in 2011. We use forward contracts to hedge a portion of the crude oil we expect to receive from our customers as a pipeline loss allowance as part of the transportation of their crude oil. We subsequently sell this crude oil at market rates. We use derivative financial instruments which fix the sales price we will receive in the future for the sale of this crude oil. We elected not to designate these derivative financial instruments as cash flow hedges.

The operating and administrative expenses of our Liquids business increased $10.7 million from the three month period ended March 31, 2012 when compared with the same period in 2011 primarily due to additional workforce related costs associated with the operational, administrative, regulatory and compliance support necessary for our systems.

Before the recognition of insurance recoveries, environmental costs increased $2.4 million for the three month period ended March 31, 2012, compared with the same period in 2011, of which, $1.9 million related to a pipeline that was struck by a third party vehicle at our New Lenox, Illinois pump station. Additional environmental costs and insurance recoveries are discussed below under *Operating Impact of Lines 6A and 6B Crude Oil Releases.*

Power costs increased $5.6 million for the three month period ended March 31, 2012, compared with the same period in 2011. The increase in power costs is primarily associated with the higher volumes of crude oil transported on our Lakehead system coupled with the additional cost of using drag reducing agents to support the higher volumes on our North Dakota and Lakehead systems.

The increase in depreciation expense of $2.0 million is directly attributable to the additional assets we have placed in service since the same period in 2011.

Operating Impact of Lines 6A and 6B Crude Oil Releases

We continue to make visible progress with the environmental cleanup, remediation and restoration of the areas affected by the crude oil releases from Lines 6A and 6B of our Lakehead system. Our total cost estimate remains at approximately $813 million, before insurance recoveries and excluding fines and penalties, for extended submerged oil recovery operations including reassessment, remediation and restoration of the area and air and groundwater monitoring, scientific studies and hydrodynamic modeling, along with legal, professional and regulatory costs through future periods. The total estimated cost for these incidents at March 31, 2012 remains unchanged based on a review of costs and commitments incurred and our evaluation of additional information regarding requirements for environmental restoration and remediation. We continue to incur costs for air and ground water monitoring as well as professional fees, which are included in our estimates. We have the potential of incurring additional costs in connection with these incidents including modified remediation requirements, fines and penalties, as well as expenditures for litigation and settlement of claims. Our estimated costs for these incidents are based on currently available information and will be updated as considered necessary to incorporate material new information as it becomes available.

The claims for the crude oil releases from Lines 6A and 6B were covered under a then effective insurance coverage that expired on April 30, 2011, which had an aggregate limit of $650 million for pollution liability. Based on our remediation spending through March 31, 2012, Enbridge Inc. or Enbridge, exceeded the limits of coverage under this insurance policy. 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's current comprehensive insurance program, expiring April 30, 2012 has a current liability aggregate limit of $575.0 million, including pollution liability. Enbridge will renew its liability insurance and expects to increase the aggregate limit of coverage effective May, 1 2012 through April 30, 2013.

The increase of $37.4 million in environmental expenses, net of recoveries, for the three month period ended March 31, 2012 when compared to the same period in 2011 is primarily due to the recognition of $35.0 million for insurance recoveries, as a reduction to environmental costs, for the Line 6B crude oil release in the first quarter of 2011 compared with no such insurance recoveries recognized for the three month period ended March 31, 2012.

Future Prospects Update for Liquids

The following discussion provides an update to the status of projects that we and Enbridge are currently developing and should be read in conjunction with the information included in Item 7. *Management's Discussion and Analysis of Financial Condition and Results of Operations* of our Annual Report on Form 10-K for the year ended December 31, 2011.

Eastern Market Expansion

In October 2011, we and Enbridge announced two projects that will provide increased access to refineries in the United States Upper Mid-west and in Ontario, Canada for light crude oil produced in western Canada and the United States. One of the projects involves the expansion of our Line 5 light crude line between Superior, Wisconsin and Sarnia, Ontario by 50,000 Bpd, at a total cost of approximately $100 million, of which we are obligated for $95 million, while Enbridge is obligated for the remaining $5 million. Complementing the Line 5 expansion, Enbridge plans on reversing a portion of its Line 9 in western Ontario to permit crude oil movements eastbound from Sarnia as far as Westover, Ontario. Subject to regulatory approvals, the Line 5 expansion is targeted to be in service during the first quarter of 2013 and the Line 9 reversal is targeted to be in service in late 2013. The project will enable growing light crude production from the Bakken shale and from Alberta to meet refinery needs in Michigan, Ohio and Ontario. The project provides another much needed transportation outlet for light crude, mitigating the current discounting of supplies in this basin, while also providing more favorable supply costs to refiners currently dependent on crudes priced off of the Atlantic basin.

Berthold Rail

In December 2011, we announced that we will be proceeding with the Berthold Rail Project, a $145 million investment that will provide an interim solution to shipper needs in the Bakken region. The project will expand capacity into the Berthold, North Dakota Terminal by 80,000 barrels per day and includes the construction of a three unit-train loading facility, crude oil tankage and other terminal facilities adjacent to existing facilities. A regulatory filing is in progress and detailed design is proceeding to enable construction to commence in April 2012 with a scheduled in-service date by early-2013.

Bakken Pipeline Expansion

In August 2010, we announced the Bakken Project, a joint crude oil pipeline expansion project with an affiliate of Enbridge in the Bakken and Three Forks formations located in the states of Montana and North Dakota and the Canadian provinces of Saskatchewan and Manitoba. The Bakken Project will follow our existing rights-of-way in the United States and those of Enbridge Income Fund Holdings in Canada to terminate and deliver to the Enbridge Mainline system's terminal at Cromer, Manitoba, Canada. The United States portion of the Bakken Project will expand the United States portion of the Portal Pipeline, which was reversed in 2011, and flowing oil from Berthold to the United States border into Steelman by constructing two new pumping stations in Kenaston and Lignite, North Dakota, and replacing an 11-mile segment of the existing 12-inch diameter pipeline that runs from these two locations. The project also calls for an expansion at our existing terminal and station in Berthold, North Dakota. When completed, the Bakken Project will provide capacity of 145,000 Bpd. This project, with the North Dakota mainline, will result in a total takeaway capacity for this region of 355,000 Bpd. The United States portion of the Bakken Project will have an estimated cost of approximately $340 million. We commenced construction in July of 2011 with an expected in-service date in the first quarter of 2013. In February 2012, we announced, in conjunction with Enbridge Income Fund Holdings in Canada, a second open season for the Bakken Pipeline Expansion to allow shippers the option of securing future capacity once the expansion is completed. The open season resulted in additional term commitments to support the Bakken Project.

Bakken Access Program

In October 2011, we announced the Bakken Access Program, a series of projects totaling approximately $100 million, which represents an upstream expansion that will further complement our Bakken expansion, as discussed above. This expansion program will substantially enhance our gathering capabilities on the North Dakota system by 100,000 Bpd. This program is expected to be in service by early 2013, and it involves increasing pipeline capacities, construction of additional storage tanks and the addition of truck access facilities at multiple locations in western North Dakota.

Cushing Terminal Storage Expansion Project

In January 2012, we began construction on four new tanks at our Cushing South Terminal with an approximate shell capacity of 1.2 million barrels. The new tanks will have an estimated cost of $33 million and are targeted to be in service by December 2012.

During late 2010, we began construction on nine new storage tanks at our Cushing terminal with an approximate shell capacity of 3.2 million barrels. As of March 31, 2012, we have spent approximately $50 million on this project with eight of the nine tanks having been completed and placed into service, with the last remaining tank being placed into service in April 2012.

Line Replacement Program

On May 12, 2011, we announced plans to replace 75-miles of non-contiguous sections of Line 6B of our Lakehead system at an estimated cost of $286.0 million. Our Line 6B pipeline runs from Griffith, Indiana through Michigan to the international border at the St. Clair River. Subject to regulatory approvals, the new segments of pipeline will be constructed mostly in 2012 and are targeted to be placed in service by the first quarter of 2013 in consultation with, and to minimize impact to, refiners and shippers served by Line 6B crude oil deliveries. These costs will be recovered through our Facilities Surcharge Mechanism, or FSM, that is part of the system-wide rates of the Lakehead system. We have subsequently revised the scope of this project to increase the cost by approximately $30.0 million, which will bring the total capital for this replacement program to an estimated cost of $316.0 million. The $30.0 million of additional costs do not currently have recovery under the FSM.

Enbridge United States Gulf Coast Projects

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 on our Lakehead pipeline system.

Flanagan South Pipeline

Enbridge's Flanagan South Pipeline project will transport more volumes into Cushing, Oklahoma and twin their existing Spearhead pipeline, which starts at the hub in Flanagan, Illinois and delivers volumes into the Cushing hub. Based on the results of a second open season held in the first quarter of 2012, the Flanagan South Pipeline will be upsized to a 36-inch diameter line with an initial annual capacity of 585,000 bpd. Subject to regulatory and other approvals, the pipeline is expected to be in service by the middle of 2014.

Seaway Crude Pipeline

In December 2011, Enbridge completed the acquisition of a 50 percent interest in the Seaway Crude Pipeline System, or Seaway, from ConocoPhillips. Seaway is a 670 mile pipeline that includes a 500 mile, 30 inch pipeline from Freeport, Texas to Cushing, Oklahoma long-haul system, as well as a Texas City Terminal and Distribution System which serves refineries in Houston and Texas City areas. Seaway also includes 6.8 million barrels of crude oil tankage on the Texas Gulf Coast and four import docks at two locations. The remaining 50 percent interest in Seaway is owned by Enterprise Products Partners L.P., or Enterprise Products. Enbridge and Enterprise Products have announced plans to reverse the direction of the 500 mile Seaway pipeline to enable it to transport oil from Cushing, Oklahoma to the United States Gulf Coast. The initial 150,000 bpd of capacity on the reversed system is expected to be available by the second quarter of 2012. Following pump station additions and modifications, which are expected to be completed by the first quarter of 2013, capacity would increase to 400,000 bpd assuming a mix of light and heavy grades of crude oil.

In March 2012, Enbridge and Enterprise Products announced that they secured sufficient capacity commitments from shippers to proceed with an expansion of the Seaway pipeline that will more than double its capacity to 850,000 bpd by the middle of 2014. In addition, a proposed 85 mile pipeline is expected to be built from Enterprise Product's ECHO crude oil terminal southeast of Houston to the Port Arthur/Beaumont, Texas refining center and will offer incremental capacity of 560,000 bpd and is expected to be available in early 2014.

Other Matters

Line 6B Pipeline Integrity Plan

We completed on schedule all the work required by the Pipeline and Hazardous Materials Safety Administration, or PHMSA, that we agreed to perform as part of our restart of Line 6B. Additionally, a new line was installed beneath the St. Clair River in March 2011 and was tied into the existing pipeline during June 2011, and we announced plans for a pipeline replacement plan as discussed above. Additional integrity expenditures, which could be significant, may be required after this initial remediation program. The total cost of these integrity measures is separate from the environmental liabilities discussed above. The pipeline integrity and replacement costs will be capitalized or expensed in accordance with our capitalization policies as these costs are incurred, the majority of which are expected to be capital in nature. We expect to incur ongoing operating costs for pipeline integrity measures to ensure both regulatory compliance and to maintain the overall integrity of our pipeline systems.

We filed a supplement to our FSM, which became effective on April 1, 2011, for recovery of $175 million of capital costs and $5 million of operating costs for the 2010 and 2011 Line 6B Pipeline Integrity Plan. The costs associated with the Line 6B Pipeline Integrity Plan, which include an equity return component, interest expense and an allowance for income taxes will be recovered over a 30-year period, while operating costs will be recovered through our annual tolls for actual costs incurred. These costs include costs associated with the PHMSA Corrective Action Order and other required integrity work.

Natural Gas

The following tables set forth the operating results of our Natural Gas segment assets and approximate average daily volumes of our major systems in millions of British Thermal Units, or MMBtu/d, for the periods presented.

	For the three month period ended March 31,	
	2012	2011
	(unaudited; in millions)	
Operating revenues	$ 1,169.2	$ 1,449.7
Cost of natural gas	965.6	1,293.8
Environmental costs, net of recoveries	—	(0.4)
Operating and administrative	117.6	93.6
Depreciation and amortization	33.1	39.9
Operating expenses	1,116.3	1,426.9
Operating Income	$ 52.9	$ 22.8
Operating Statistics (MMBtu/d)		
East Texas	1,319,000	1,315,000
Anadarko	942,000	929,000
North Texas	315,000	339,000
Total	2,576,000	2,583,000

Three month period ended March 31, 2012 compared with three month period ended March 31, 2011

The primary factors affecting the operating income of our Natural Gas business for the three month period ended March 31, 2012 as compared with the same period of 2011 are as follows:

- $12.8 million increase in unrealized, non-cash, mark-to-market net gains from derivative instruments that do not qualify for hedge accounting treatment under authoritative accounting guidance, as compared with the same period of 2011;
- The results from our natural gas business were unfavorably impacted by approximately $6.6 million due to the downtime associated with a fire at a third-party fractionation facility which resulted in production from our Anadarko system being shut-in for approximately two weeks. Comparatively during the first quarter 2011, adverse weather conditions and plant downtime had an approximate $13 million negative impact to the gross margin.
- $24.0 million increase in operating and administrative costs primarily associated with increases in additional workforce and operational related costs associated with the expansion of our systems and $7.4 million in investigation costs related to accounting misstatements at our Trucking and NGL marketing subsidiary;
- $6.8 million decrease in depreciation expense primarily due to a revision in depreciation rates for the Anadarko, North Texas and East Texas systems effective July 1, 2011, which resulted in a decrease of $8.5 million in depreciation expense. This decrease was partially offset with an increase in depreciation associated with additional assets that were put in service during 2011; and
- NGL and natural gas volume growth on our Anadarko and Elk City systems contributed to increased revenues on these systems.

Changes in the average forward prices of natural gas, NGLs and condensate from December 31, 2011 to March 31, 2012 produced unrealized, non-cash, mark-to-market net gains of $3.7 million from the non-qualifying commodity derivatives we use to economically hedge a portion of the natural gas, NGLs and condensate resulting from the operating activities of our Natural Gas business. Comparatively, changes in the average forward prices of natural gas, NGLs and condensate from December 31, 2010 to March 31, 2011, produced unrealized, non-cash, mark-to-market net losses of $9.1 million from the non-qualifying commodity derivatives we use to economically hedge a portion of the natural gas, NGLs and condensate resulting from the operating activities of our Natural Gas business. These movements in the forward prices of natural gas, NGLs and condensate that occurred during the first quarter of 2012 as compared to the first quarter of 2011, resulted in additional unrealized non-cash, mark-to-market net gains from our derivative activities between periods.

The following table depicts the effect that unrealized, non-cash, mark-to-market net gains and losses had on the operating results of our Natural Gas segment for the three month period ended March 31, 2012 and 2011:

	For the three month period ended March 31,	
	2012	**2011**
	(unaudited; in millions)	
Hedge ineffectiveness	$(1.8)	$ 1.2
Non-qualified hedges	5.5	(10.3)
Derivative fair value gains (losses)	$ 3.7	$ (9.1)

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. We are exposed to fluctuations in commodity prices in the near term on approximately 30 to 40 percent of the natural gas, NGLs and condensate we expect to receive as compensation for our services. As a result of this unhedged commodity price exposure, our gross margin, representing revenue less cost of natural gas, generally increases when the prices of these commodities are rising and generally decreases when the prices are declining.

Volumes on all three of our systems were relatively flat for the three month period ended March 31, 2012. However, NGL revenues we receive on our Anadarko system were higher than 2011 due to additional NGL processing capabilities at the Allison plant which was completed in late 2011. While this additional capacity has benefited the system, it was negatively impacted when a third-party facility shut down due to an incident. The results from our natural gas business were unfavorably impacted by approximately $6.6 million due to the downtime associated with a fire at a third-party fractionation facility which resulted in production from our Anadarko system being shut-in for approximately two weeks.

For the three month period ended March 31, 2011, our volumes were negatively impacted due to uncharacteristically cold weather and freezing precipitation in February 2011 that moved through Oklahoma and north Texas with temperatures dropping below freezing for extended periods. These conditions resulted in mechanical issues with our producers' equipment and impacted their ability to flow natural gas. Producers shut in significant volumes during this period, which reduced the average daily volumes on our systems by approximately 56,000 MMBtu/d. Additionally, mechanical problems on two of our plants required that they be taken out of service for extended periods during the first quarter of 2011 to correct these conditions. The adverse weather conditions and plant downtime had an approximate $13 million negative impact to the gross margin of our Natural Gas business for the first quarter ended 2011.

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, 2012 was $27.2 million, representing an increase of $1.3 million from the $25.9 million we produced for the same period in 2011.

Operating and administrative costs of our Natural Gas segment were $24.0 million higher for the three month period ended March 31, 2012 compared to the same period in 2011 primarily due to an increase in workforce and operational related costs associated with the expansion of our systems. In addition, we recognized $7.4 million associated with investigative costs related to the accounting misstatements at our Trucking and NGL marketing subsidiary for the three month period ended March 31, 2012, with no similar costs for the same period in 2011.

Future Prospects for Natural Gas

The following discussion provides an update to the status of projects that we and Enbridge are currently developing and should be read in conjunction with the information included in Item 7. *Management's Discussion and Analysis of Financial Condition and Results of Operations* of our Annual Report on Form 10-K for the year ended December 31, 2011.

Texas Express Pipeline

In September 2011, we announced a joint venture among us, Enterprise Products Partners L.P., or Enterprise Products, and Anadarko Petroleum Corporation, or Anadarko, to design and construct a new NGL pipeline and two new NGL gathering systems, collectively referred to as the Texas Express Pipeline project, or TEP. In April 2012, DCP Midstream LLC, or DCP, announced plans to purchase a 10 percent ownership in the NGL pipeline portion of TEP from Enterprise. After DCP's purchase, the NGL pipeline portion of TEP is owned 35 percent by Enterprise Products, our ownership continues to be 35 percent, 20 percent by Anadarko and 10 percent by DCP, while the ownership in two new NGL gathering systems will be owned 45 percent by Enterprise, 35 percent by us and 20 percent by Anadarko. Our portion of the total estimated cost is $385 million. The pipeline will originate at Skellytown, Texas and extend approximately 580 miles to NGL fractionation and storage facilities in Mont Belvieu, Texas. The pipeline will have an initial capacity of approximately 280,000 Bpd and will be readily expandable to approximately 400,000 Bpd. Approximately 250,000 Bpd of capacity has been subscribed on the pipeline.

In addition, the TEP joint venture project will include two new NGL gathering systems. The first will connect TEP NGL pipeline to natural gas processing plants in the Anadarko/Granite Wash production area located in the Texas Panhandle and Western Oklahoma. The second NGL gathering system will connect the new pipeline to central Texas, Barnett Shale processing plants. Volumes from the Rockies, Permian Basin and Mid-Continent regions will be delivered to the TEP system utilizing Enterprise's existing Mid-America Pipeline assets between the Conway hub and Enterprise's Hobbs NGL fractionation facility in Gaines County, Texas. In addition, volumes from and to the Denver-Julesburg Basin in Weld County, Colorado will be able to access TEP through the connecting Front Range Pipeline as proposed by Enterprise, DCP and Anadarko. Enterprise will construct and serve as the operator of the pipeline, while we will build and operate the new gathering systems. The pipeline and portions of the gathering systems are expected to begin service in mid-2013, subject to regulatory approvals and finalization of commercial agreements.

TEP will serve as a link between growing supply sources of NGLs in the Anadarko region and the primary end use market on the United States Gulf Coast and will be providing guaranteed NGL access to the primary United States petrochemical market located in Mont Belvieu. TEP will assist us in fulfilling our strategic objective of expanding our presence in the natural gas and NGL value chain and provide a new source of strong and stable cash flow.

Ajax Cryogenic Processing Plant

In August 2011, we announced plans to construct an additional processing plant and other facilities, including compression and gathering infrastructure, on our Anadarko system at a cost of $230 million, which we refer to as our Ajax Plant. The Ajax Plant will have a planned capacity of 150 MMcf/d and is intended to meet the continued strength of horizontal drilling activity in this area. The Ajax Plant is anticipated to be in service in early 2013.

The Ajax plant, when operational, in addition to the Allison Plant, will increase the total processing capacity on our Anadarko system to approximately 1,200 MMcf/d.

South Haynesville Shale Expansion

In February 2010, we announced plans to expand our East Texas system by constructing three lateral pipelines into the East Texas portion of the Haynesville shale, together with a large diameter lateral pipeline from Shelby County to Carthage which will further expand our recently completed Shelby County Loop. The expansion into the Haynesville shale area increased the capacity of our East Texas system by 900 million cubic feet per day, or MMcf/d. We completed construction of a portion of the pipeline for the project during the second quarter of 2010 and the main trunkline to Carthage in December 2010, and we expect construction of the facilities will be completed in 2012. Future compression can be added, as needed, after the completion of the facilities.

In April 2011, we announced plans to invest an additional $175 million to expand our East Texas system. We have signed long-term agreements with four major natural gas producers along the Texas side of the Haynesville shale to provide gathering, treating and transmission services in Shelby, San Augustine and Nacogdoches counties. The projects involve construction of gathering and related market outlet pipelines and related treating facilities in the Texas Haynesville shale. In light of weak natural gas prices and lower levels of producer activity, the Partnership has deferred portions of its Haynesville natural gas expansion pending increases in drilling activity.

Marketing

The following table sets forth the operating results of our Marketing segment assets for the periods presented:

	For the three month period ended March 31,	
	2012	**2011**
	(unaudited; in millions)	
Operating revenues	$328.0	$537.4
Cost of natural gas	331.3	535.7
Operating and administrative	1.7	1.6
Operating expenses	333.0	537.3
Operating income (loss)	$ (5.0)	$ 0.1

Our Marketing business derives a majority of its operating income from selling natural gas received from producers on our Natural Gas segment pipeline assets to customers utilizing the natural gas. A majority of the natural gas we purchase is produced in Texas where we have expanded access to several interstate natural gas pipelines over the past several years, which we can use to transport natural gas to market hubs where it can be sold.

Three month period ended March 31, 2012 compared with three month period ended March 31, 2011

Contributing to the operating loss of our Marketing business were relatively stable and low natural gas prices during the three month period ended March 31, 2012, due to limited opportunities to benefit from significant price differentials between market centers. As a result, our marketing operations generated a $0.5 million gain for the three month period ended March 31, 2012 as compared to a $4.6 million gain for the three month period ended March 31, 2011.

Included in the operating results of our Marketing segment for the three month period ended March 31, 2012 were unrealized, non-cash, mark-to-market net losses of $1.8 million as compared with the $2.9 million of unrealized non-cash, mark-to-market net losses for the same period in 2011 associated with derivative financial instruments that do not qualify for hedge accounting treatment under authoritative accounting guidance. This decrease in loss for the three month period ended March 31, 2012 as compared to the same period in 2011, was primarily attributed to the realization of financial instruments used to hedge our storage positions.

Operating income for the three month period ended March 31, 2012 was also negatively affected by non-cash charges to inventory of $2.0 million, which we recorded to reduce the cost basis of our natural gas inventory to net realizable value. Similar charges did not occur in the comparable period of 2011. Since we financial hedge our storage positions, these charges will be recovered when the physical natural gas inventory is sold or as the financial hedges are realized.

Corporate

Our interest cost for the three month periods ended March 31, 2012 and 2011 is comprised of the following:

	For the three month period ended March 31,	
	2012	2011
	(unaudited; in millions)	
Interest expense	$83.6	$79.4
Interest capitalized	6.4	1.5
Interest cost incurred	$90.0	$80.9
Weighted average interest rate	*6.5%*	*6.4%*

Three month period ended March 31, 2012 compared with three month period ended March 31, 2011

The increase in interest expense between the three month periods ended March 31, 2012 and 2011 is primarily the result of a higher weighted average outstanding debt balance during the three month period ended March 31, 2012 as compared with the same period in 2011. The increased weighted average outstanding debt balance was primarily a result of the issuance and sale in September 2011 of $600 million of our 4.20% senior unsecured notes due 2021 and an additional $150 million of our 5.50% senior unsecured notes due 2040, partially offset by a lower commercial paper balance.

Other Matters

Alberta Clipper Pipeline Joint Funding Arrangement and Regulatory Accounting

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. The Alberta Clipper Pipeline was mechanically complete in March 2010 and was ready for service on April 1, 2010. In connection with the joint funding arrangement, we allocated earnings derived from operating the Alberta Clipper Pipeline in the amount of $13.0 million and $14.7 million to our General Partner for its 66.67 percent share of the earnings of the Alberta Clipper Pipeline for the three month periods ended March 31, 2012 and 2011, 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.

Proceeds from Claim Settlements

In April 2011, we received proceeds of $11.6 million for settlement of claims we made for payment from unrelated parties in connection with operational matters that occurred in the normal course of business. We recorded $5.6 million as a reduction to "Operating and administrative" expenses of our Liquids segment and $6.0 million as "Other income" to Corporate activities in our consolidated statements of income for the period ended March 31, 2011.

LIQUIDITY AND CAPITAL RESOURCES

Available Liquidity

As set forth in the following table, we had in excess of $1.8 billion of liquidity available to us at March 31, 2012 to meet our ongoing operational, investment and financing needs, as well as the funding requirements associated with the environmental costs resulting from the crude oil releases on Lines 6A and 6B.

	(unaudited; in millions)
Cash and cash equivalents	$ 277.3
Total credit available under New Credit Facility	2,000.0
Less: Amounts outstanding under New Credit Facility	—
Principal amount of commercial paper issuances	325.0
Letters of credit outstanding	148.9
Total	$1,803.4

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 New Credit Facility. Margin requirements associated with our derivative transactions are generally supported by letters of credit issued under our New Credit Facility.

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 New Credit Facility. Likewise, we anticipate initially retiring our maturing debt with similar borrowings on our New Credit Facility. 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.

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 may 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.

Available Credit

Our two primary sources of liquidity are provided by our commercial paper program and our New Credit Facility. We have a $1.5 billion commercial paper program that is supported by our New Credit Facility, 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 New Credit Facility.

Credit Facility

In September 2011, we entered into a new credit agreement with Bank of America, as administrative agent, which we refer to as the New Credit Facility. The new agreement is a committed senior unsecured revolving credit facility that permits aggregate borrowings of up to, at any one time outstanding, $2 billion, a letter of credit subfacility and a swing line subfacility with a maturity date of September 26, 2016.

The amounts we may borrow under the terms of our New Credit Facility are reduced by the face amount of our letters of credit outstanding. It is our policy to maintain availability at any time under our New Credit Facility that is at least equal to the amount of commercial paper that we have outstanding at such time. Taking that policy into account, at March 31, 2012, we could borrow $1,526.1 million under the terms of our New Credit Facility, determined as follows:

	(in millions)
Total credit available under New Credit Facility	$2,000.0
Less: Amounts outstanding under New Credit Facility	—
Principal amount of commercial paper outstanding	325.0
Letters of credit outstanding	148.9
Total amount we could borrow at March 31, 2012	$1,526.1

Individual London Inter-Bank Offered Rate, or LIBOR rate, borrowings under the terms of our New Credit Facility 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 New Credit Facility and do not require any cash repayments or prepayments. For the three month periods ended March 31, 2012 and 2011 we have not renewed any LIBOR rate borrowings or base rate borrowings, on a non-cash basis.

Effective September 30, 2011, our New Credit Facility was amended to further modify the definition of Consolidated Earnings Before Income Taxes Depreciation and Amortization, or Consolidated EBITDA, as set forth in the terms of our New Credit Facility, to increase from $550 million to $650 million, the aggregate amount of the costs associated with the crude oil releases on Lines 6A and 6B that are excluded from the computation of Consolidated EBITDA. Specifically, the costs allowed to be excluded from Consolidated EBITDA are those for emergency response, environmental remediation, cleanup activities, costs to repair the pipelines, inspection costs, potential claims by third parties and lost revenue. At March 31, 2012 we were in compliance with the terms of our financial covenants.

Commercial Paper

At March 31, 2012, we had $325.0 million of commercial paper outstanding at a weighted average interest rate of 0.45%, excluding the effect of our interest rate hedging activities. Under our commercial paper program, we had net borrowings of approximately $50.1 million during the three month period ended March 31, 2012, which include gross issuances of $1,799.4 million and gross repayments of $1,749.3 million. Our policy is that the commercial paper we can issue is limited by the amounts available under our New Credit Facility up to an aggregate principal amount of $1.5 billion.

Joint Funding Arrangement for Alberta Clipper Pipeline

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. 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, at which time we also terminated the A1 Credit Agreement. The promissory note payable, which we refer to as 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, 2012, we had approximately $336.0 million outstanding under the A1 Term Note.

Our General Partner also made equity contributions totaling $3.2 million to the Enbridge Energy Limited Partnership, or OLP, during the three month periods ended March 31, 2011 to fund its equity portion of the construction costs associated with the Alberta Clipper Pipeline. No such contributions were made during the three month period ended March 31, 2012. The OLP paid a distribution of $15.8 million to our General Partner and its affiliate during the three month period ended March 31, 2012 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 $13.0 million to our General Partner for its 66.67 percent share of the earnings of the Alberta Clipper Pipeline for the three month period ended March 31, 2012. We allocated $14.7 million for the same three month period ended March 31, 2011. 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.

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 2012, we expect to spend approximately $2,120 million 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. Of this amount, we made capital expenditures of $261.3 million in the three month period ended March 31, 2012. At March 31, 2012, we had approximately $587.0 million in outstanding purchase commitments attributable to capital projects for the construction of assets that will be recorded as property, plant and equipment during 2012.

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 pursue potential acquisitions with a focus on natural gas pipelines, NGL pipelines, refined products pipelines, terminals and related facilities. We will seek opportunities for accretive acquisitions throughout the United States, particularly in the United States Gulf Coast area, where we anticipate making asset acquisitions in and around our existing Natural Gas business. We expect to obtain the funds needed to make acquisitions through a combination of cash flows from operating activities, borrowings under our New Credit Facility 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 includes 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, 2012. Although we anticipate making these expenditures in 2012, these estimates may change due to factors beyond our control, including weather-related issues, construction timing, 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. We made capital expenditures of $261.3 million, including $22.9 million on core maintenance activities, for the three month period ended March 31, 2012. For the full year ending December 31, 2012, we anticipate our capital expenditures to approximate the following:

	Total Forecasted Expenditures
	(in millions)
Capital Projects	
System Enhancements	$ 580
North Dakota Expansion Program	450
Liquids Integrity Program	310
Line 6B Replacement Program	270
Ajax Cryogenic Processing Plant	205
Core Maintenance Activities	115
Joint Venture Projects	
Texas Express Pipeline	190
	$2,120

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

On May 12, 2011, we announced plans to replace 75-miles of non-contiguous sections of Line 6B of our Lakehead system at an estimated cost of $286 million. Our Line 6B pipeline runs from Griffith, Indiana through Michigan to the international border at the St. Clair River. Subject to regulatory approvals, the new segments of pipeline will be constructed mostly in 2012 and are targeted to be placed in-service by the first quarter of 2013 in consultation with, and to minimize impact to, refiners and shippers served by Line 6B crude oil deliveries. These costs will be recovered through the FSM that is part of the system-wide rates of the Lakehead system. We revised the scope of this project to increase the cost by approximately $30 million, which will bring the total capital for this replacement program to an estimated cost of $316 million. The $30 million of additional costs do not currently have recovery under the FSM.

Additional integrity expenditures, which could be significant, may be required after this initial remediation program. The total cost of these integrity measures is separate from the environmental liabilities discussed above. The pipeline integrity and replacement costs will be capitalized or expensed in accordance with our capitalization policies as these costs are incurred, the majority of which are expected to be capital in nature.

We included in the supplement to our FSM, to be effective April 1, 2011, recovery of $175 million of capital costs and $5 million of operating costs for the 2010 and 2011 Line 6B Pipeline Integrity Plan. The costs associated with the Line 6B Pipeline Integrity Plan, which include an equity return component, interest expense and an allowance for income taxes will be recovered over a 30 year period, while operating costs will be recovered through our annual tolls for actual costs incurred. These costs include costs associated with the PHMSA Corrective Action Order and other required integrity work.

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 New Credit Facility, with permanent debt and equity funding being obtained when appropriate.

Environmental

Lines 6A and 6B Crude Oil Releases

During the three month period ended March 31, 2012, our cash flows were adversely affected by the approximate $51.2 million we paid for the environmental remediation, restoration and cleanup activities, excluding insurance recoveries, resulting from the crude oil releases that occurred in 2010 on Lines 6A and 6B of our Lakehead system. We anticipate that we will have paid approximately 95 percent of the total costs associated with these releases by the end of 2012.

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, 2012 for each of the indicated calendar years:

	Notional	2012	2013	2014	2015	2016	Total [4]
			(in millions)				
Swaps							
Natural gas [1]	117,086,412	$ —	$ 8.6	$ 0.1	$—	$—	$ 8.7
NGL [2]	4,487,683	(7.5)	(11.5)	(3.5)	(0.5)	—	(23.0)
Crude Oil [2]	5,307,080	(15.0)	(16.3)	(5.6)	2.1	0.3	(34.5)
Options							
Natural gas—puts purchased [1]	1,642,500	—	1.7	—	—	—	1.7
NGL—puts purchased [2]	1,404,700	8.6	1.7	—	—	—	10.3
Crude Oil —puts purchased [2]	48,125	0.3	—	—	—	—	0.3
Forward contracts							
Natural gas [1]	45,379,457	0.9	0.5	0.1	0.1	0.1	1.7
NGL [2]	9,913,728	5.4	0.4	—	—	—	5.8
Crude Oil [2]	2,342,269	2.7	—	—	—	—	2.7
Power [3]	147,817	(0.6)	(0.4)	(0.6)	—	—	(1.6)
Totals		$ (5.2)	$(15.3)	$(9.5)	$ 1.7	$ 0.4	$(27.9)

(1) Notional amounts for natural gas are recorded in millions of British thermal units, or MMBtu.
(2) Notional amounts for NGL and crude oil are recorded in Barrels, or Bbl.
(3) Notional amounts for power are recorded in Megawatt hours, or MWh.
(4) Fair values exclude an immaterial credit adjustment at March 31, 2012.

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, 2012 for each of the indicated calendar years:

	Notional Amount	2012	2013	2014	2015	2016	Thereafter	Total [1]
				(in millions)				
Interest Rate Derivatives								
Interest Rate Swaps:								
Floating to Fixed	$1,925.0	$ (20.0)	$(24.2)	$(6.4)	$(3.1)	$(0.5)	$ 0.2	$ (54.0)
Fixed to Floating	$ 125.0	3.7	2.8	—	—	—	—	6.5
Pre-issuance hedges	$1,850.0	(110.4)	(49.2)	0.9	—	—	—	(158.7)
		$(126.7)	$(70.6)	$(5.5)	$(3.1)	$(0.5)	$ 0.2	$(206.2)

(1) Fair values are presented in millions of dollars and exclude credit adjustments of approximately $7.2 million of gains at March 31, 2012.

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,		Variance 2012 vs. 2011 Increase (Decrease)
	2012	2011	
	(unaudited; in millions)		
Total cash provided by (used in):			
Operating activities	$ 257.5	$ 260.1	$ (2.6)
Investing activities	(272.0)	(189.4)	(82.6)
Financing activities	(131.1)	(65.9)	(65.2)
Net increase in cash and cash equivalents	(145.6)	4.8	(150.4)
Cash and cash equivalents at beginning of year	422.9	144.9	278.0
Cash and cash equivalents at end of period	$ 277.3	$ 149.7	$ 127.6

Operating Activities

Net cash provided by our operating activities decreased $2.6 million for the three month period ended March 31, 2012 compared with the same period in 2011 primarily due to changes in our working capital accounts for the three month period ended March 31, 2012 compared to the same period of 2011, coupled with general timing differences in the collection on and payment of our current and related party accounts. The changes in working capital accounts for the three month period ended March 31, 2012 were also affected by $52.3 million of environmental costs paid, which included $51.2 million of costs associated with the Lines 6A and 6B crude oil releases, as compared with, $90.2 million of environmental costs paid offset by $35.0 million of environmental insurance recoveries, in the same period of 2011.

Investing Activities

Net cash used in our investing activities during the three month period ended March 31, 2012 increased by $82.6 million compared to the same period of 2011 primarily due to additions to property, plant and equipment in 2012 related to various enhancement projects.

Financing Activities

The net cash used in our financing activities increased $65.2 million during the three month period ended March 31, 2012 compared to the same period in 2011 primarily due to the following:

	(unaudited; in millions)
Net proceeds related to Class A common units issued in 2011 [1]	$(57.1)
Increase in distributions to our partners in 2012 compared to 2011	(27.4)
Increase in net affiliate repayments in 2012 compared to 2011	(8.6)
Increase in net borrowings on our commercial paper in 2012 compared to 2011	25.1
Decrease in capital contributions from our General Partner and its affiliate for its ownership interest in the Alberta Clipper Pipeline	(3.2)
Decrease in distributions to our General Partner and its affiliate for its ownership interest in the Alberta Clipper Pipeline in 2012 compared to 2011	6.0
	$(65.2)

(1) Includes $1.2 million of contributions from the General Partner to maintain its two percent interest.

SUBSEQUENT EVENTS

Distribution to Partners

On April 30, 2012, the board of directors of Enbridge Management declared a distribution payable to our partners on May 15, 2012. The distribution will be paid to unitholders of record as of May 7, 2012, of our available cash of $180.7 million at March 31, 2012, or $0.53250 per limited partner unit. Of this distribution, $159.4 million will be paid in cash, $20.9 million will be distributed in i-units to our i-unitholder and $0.4 million will be retained from our General Partner in respect of the i-unit distribution to maintain its two percent general partner interest.

Distribution to Series AC Interests

On April 30, 2012, 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, declared a distribution payable to the holders of the Series AC general and limited partner interests. The OLP will pay $16.8 million to the noncontrolling interest in the Series AC, while $8.4 million will be paid to us.

REGULATORY MATTERS

FERC Transportation Tariffs

Effective April 1, 2012, we filed our annual tariff rate adjustment with the FERC to reflect true-ups for the difference between estimated and actual cost and throughput data for the prior year and our projected costs and throughput for 2012 related to our expansion projects. Also included was a supplement to our FSM for recovery of the costs related to the 2010 and 2011 Line 6B Integrity Program, including costs associated with the PHMSA Corrective Action Order and as discussed in Note 9. *Commitments and Contingencies—Pipeline Integrity Plan*. The FSM, which was approved in July 2004, is a component 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 decreased the average transportation rate for crude oil movements from the Canadian border to Chicago, Illinois by approximately $0.22 per barrel, to an average of approximately $1.60 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.

On May 2, 2011, we filed FERC Tariff 45.0.0 to establish International Joint Tariff rates applicable to the transportation of petroleum from all receipt points in western Canada on Enbridge Pipelines Inc., or EPI's, Canadian Mainline system to all delivery points on the Lakehead pipeline system owned by the OLP and delivery points on the Canadian mainline located downstream of the Lakehead system. This tariff filing became effective July 1, 2011.

Effective July 1, 2011, we increased the rates for transportation on our Lakehead, North Dakota and Ozark systems in compliance with the indexed rate ceilings allowed by the FERC. In May 2011, the FERC determined that the annual change in the Producer Price Index for Finished Goods, or PPI-FG, plus 2.65 percent (PPI-FG + 2.65 percent) should be the oil pricing index for the five year period ending July 2016. The index is used to establish rate ceiling levels for oil pipeline rate changes. The increase in rates is due to an increase in the Producer Price Index for Finished Goods as compared with prior periods. For our Lakehead system, indexing applies only to the base rates and does not apply to the SEP II, Terrace and Facilities surcharges, which include the Southern Access Pipeline and Alberta Clipper Project.

Effective December 19, 2011, we modified the terms of our transportation tariff on our Ozark system to implement a lottery process to allocate new shipper capacity if and when the number of new shippers nominating on the system precludes any individual new shipper from being allocated a minimum batch. Additionally, we increased the minimum accepted batch size from 10,000 Bpd to 30,000 Bpd to ensure accurate delivery measurement.

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, 2011, 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 and fractionation margins, which is the relative difference between the price we receive from NGL sales and the corresponding cost of natural gas purchases. Our interest rate risk exposure does not exist within any of our segments, but exists at the corporate level where our fixed and 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 commodity prices and interest rates, 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 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, 2012.

				Fair Value [2] at	
Date of Maturity & Contract Type	**Accounting Treatment**	**Notional**	**Average Fixed Rate [1]**	**March 31, 2012**	**December 31, 2011**
			(dollars in millions)		
Contracts maturing in 2013					
Interest Rate Swaps—Pay Fixed	Cash Flow Hedge	$800	3.24%	$ (38.3)	$ (42.2)
Interest Rate Swaps—Pay Fixed	Non-qualifying	$125	4.35%	$ (5.9)	$ (6.8)
Interest Rate Swaps—Pay Float	Non-qualifying	$125	4.75%	$ 6.5	$ 7.5
Contracts maturing in 2014					
Interest Rate Swaps—Pay Fixed	Cash Flow Hedge	$200	0.56%	$ —	$ 0.2
Contracts maturing in 2015					
Interest Rate Swaps—Pay Fixed	Cash Flow Hedge	$300	2.43%	$ (4.9)	$ (4.7)
Contracts maturing in 2017					
Interest Rate Swaps—Pay Fixed	Cash Flow Hedge	$500	2.21%	$ (4.9)	$ (5.8)
Contracts settling prior to maturity					
2012—Pre-issuance Hedges	Cash Flow Hedge	$600	4.56%	$(110.4)	$(123.7)
2013—Pre-issuance Hedges	Cash Flow Hedge	$500	3.98%	$ (49.2)	$ (63.1)
2014—Pre-issuance Hedges	Cash Flow Hedge	$750	3.15%	$ 0.9	$ (23.4)

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

(2) The fair value is determined from quoted market prices at March 31, 2012 and December 31, 2011, 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 $7.2 million of gains at March 31, 2012 and $19.4 million of gains at December 31, 2011.

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, 2012 and December 31, 2011.

	At March 31, 2012						At December 31, 2011	
			Wtd. Average Price [(2)]		Fair Value [(3)]		Fair Value [(3)]	
	Commodity	Notional [(1)]	Receive	Pay	Asset	Liability	Asset	Liability
Portion of contracts maturing in 2012								
Swaps								
Receive variable/pay fixed	Natural Gas	1,192,669	$ 2.40	$ 6.57	$—	$ (5.0)	$—	$ (8.1)
	NGL	273,750	$ 75.19	$ 79.34	$—	$ (1.1)	$ 0.4	$ —
	Crude Oil	180,000	$104.19	$107.00	$—	$ (0.5)	$—	$ —
Receive fixed/pay variable	Natural Gas	1,871,196	$ 4.75	$ 2.55	$ 4.1	$ —	$ 7.1	$ —
	NGL	2,414,998	$ 52.38	$ 55.02	$ 8.6	$(15.0)	$ 6.3	$(20.6)
	Crude Oil	1,556,525	$ 95.01	$104.34	$ 2.4	$(16.9)	$ 3.5	$(15.6)
Receive variable/pay variable	Natural Gas	68,445,731	$ 2.37	$ 2.36	$ 1.7	$ (0.8)	$ 2.8	$ (0.8)
Physical Contracts								
Receive variable/pay fixed	NGL	35,000	$ 52.31	$ 55.22	$—	$ (0.1)	$ 0.3	$ —
	Crude Oil	325,000	$103.44	$105.53	$—	$ (0.7)	$ 0.2	$ (0.3)
Receive fixed/pay variable	NGL	135,000	$ 46.67	$ 45.57	$ 0.2	$ —	$ 0.3	$ (1.0)
	Crude Oil	443,000	$105.07	$103.70	$ 0.7	$ (0.1)	$ 0.1	$ (0.6)
Receive variable/pay variable	Natural Gas	30,804,505	$ 2.42	$ 2.39	$ 1.0	$ (0.1)	$ 1.2	$ —
	NGL	9,422,657	$ 47.28	$ 46.73	$ 6.9	$ (1.6)	$ 8.8	$ (3.8)
	Crude Oil	1,574,270	$105.53	$103.76	$ 7.5	$ (4.7)	$ 1.5	$ (1.9)
Pay fixed	Power [(4)]	46,285	$ 27.24	$ 40.28	$—	$ (0.6)	$—	$ (0.5)
Portion of contracts maturing in 2013								
Swaps								
Receive variable/pay fixed	Natural Gas	96,846	$ 3.38	$ 5.11	$—	$ (0.2)	$—	$ (0.1)
Receive fixed/pay variable	Natural Gas	4,488,100	$ 5.11	$ 3.30	$ 8.1	$ —	$ 5.9	$ —
	NGL	1,308,010	$ 58.83	$ 67.64	$ 2.2	$(13.7)	$ 0.5	$ (8.7)
	Crude Oil	1,430,435	$ 92.11	$103.59	$ 1.6	$(17.9)	$ 3.7	$(10.0)
Receive variable/pay variable	Natural Gas	34,670,000	$ 3.40	$ 3.38	$ 0.8	$ (0.1)	$ 0.8	$ (0.1)
Physical Contracts								
Receive variable/pay variable	Natural Gas	11,599,382	$ 3.43	$ 3.39	$ 0.5	$ —	$ 0.5	$ —
	NGL	321,071	$ 60.28	$ 59.12	$ 0.4	$ —	$ 0.4	$ (0.1)
Pay fixed	Power [(4)]	42,924	$ 32.77	$ 42.82	$—	$ (0.4)	$—	$ (0.3)
Portion of contracts maturing in 2014								
Swaps								
Receive variable/pay fixed	Natural Gas	21,870	$ 3.88	$ 5.22	$—	$ —	$—	$ —
Receive fixed/pay variable	NGL	381,425	$ 77.58	$ 86.90	$—	$ (3.5)	$ 0.8	$ (1.9)
	Crude Oil	1,228,955	$ 94.27	$ 98.88	$ 1.5	$ (7.1)	$ 4.9	$ (3.1)
Receive variable/pay variable	Natural Gas	6,300,000	$ 3.92	$ 3.91	$ 0.1	$ —	$ 0.1	$ —
Physical Contracts								
Receive variable/pay variable	Natural Gas	1,115,075	$ 4.03	$ 3.90	$ 0.1	$ —	$ 0.1	$ —
Pay fixed	Power [(4)]	58,608	$ 35.37	$ 46.58	$—	$ (0.6)	$—	$ (0.5)
Portion of contracts maturing in 2015								
Swaps								
Receive fixed/pay variable	NGL	109,500	$ 88.36	$ 92.99	$ 0.1	$ (0.6)	$ 0.7	$ (0.2)
	Crude Oil	865,415	$ 97.72	$ 95.15	$ 3.4	$ (1.3)	$ 6.0	$ (0.4)
Physical Contracts								
Receive variable/pay variable	Natural Gas	1,115,075	$ 4.38	$ 4.26	$ 0.1	$ —	$ 0.1	$ —
Portion of contracts maturing in 2016								
Swaps								
Receive fixed/pay variable	Crude Oil	45,750	$ 99.31	$ 93.06	$ 0.3	$ —	$ 0.4	$ —
Physical Contracts								
Receive variable/pay variable	Natural Gas	745,420	$ 4.64	$ 4.51	$ 0.1	$ —	$ 0.1	$ —

(1) Volumes of natural gas are measured in millions of British Thermal Units, or MMBtu, whereas volumes of NGL and crude oil are measured in barrels, or Bbl. Our power purchase agreements are measured in Megawatt hours, or 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, 2012 and December 31, 2011, 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 and $0.8 million of losses at March 31, 2012 and December 31, 2011, respectively.
(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, 2012 and December 31, 2011.

	At March 31, 2012						At December 31, 2011	
					Fair Value (3)		Fair Value (3)	
	Commodity	Notional (1)	Strike Price (2)	Market Price (2)	Asset	Liability	Asset	Liability
Portion of option contracts maturing in 2012								
Puts (purchased)	NGL	1,221,450	$42.36	$ 40.12	$8.6	$—	$7.3	$—
	Crude Oil	48,125	$99.00	$104.54	$0.3	$—	$0.7	$—
Portion of option contracts maturing in 2013								
Puts (purchased)	Natural Gas	1,642,500	$ 4.18	$ 3.30	$1.7	$—	$1.2	$—
	NGL	183,250	$26.25	$ 17.91	$1.7	$—	$0.9	$—

(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, 2012 and December 31, 2011, 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 losses at March 31, 2012 and $0.1 million of losses at December 31, 2011.

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, 2012	December 31, 2011
	(in millions)	
Counterparty Credit Quality*		
AAA	$ 0.9	$ (0.2)
AA	(79.9)	(98.4)
A	(152.6)	(160.7)
Lower than A	4.7	4.8
	$(226.9)	$(254.5)

* As determined by nationally-recognized statistical ratings organizations.

Item 4. Controls and Procedures

MATERIAL WEAKNESS PREVIOUSLY DISCLOSED

We disclosed in Item 9A. *Controls and Procedures* of our Annual Report on Form 10-K, for the year ended December 31, 2011, that we had identified a material weakness in our internal controls over financial reporting with respect to our trucking and NGL marketing subsidiary related to misconduct and collusion of local management and staff that resulted in accounting misstatements. We determined that these misstatements had no material effect on our consolidated financial statements for the current or any prior years during which the activities above occurred.

The principle factors at the referenced subsidiary that contributed to the material weakness were: 1) absence of appropriate tone and control culture, 2) controls that were not effective to ensure accurate and timely reporting assets and liabilities in the instance of collusion by local management and staff, and 3) monitoring controls were not sufficient to detect or deter circumvention of accounting controls or accounting misstatements timely.

REMEDIATION

Management, with the participation of the principal executive officer and principal financial officer, implemented changes to the Partnership's internal control over financial reporting related to the referenced subsidiary to remediate the material weakness described above. The following changes to the Partnership's internal control systems and procedures related to the referenced subsidiary included:

- We have appointed replacements for management at the subsidiary, who separated from the organization in 2011.
- We added an additional layer of review of payments and accounting activities at the subsidiary.
- A new accounting manager of the subsidiary was appointed.
- We implemented new centralized reporting structures for various groups, including risk management and information technology.

We are also centralizing critical control functions, including accounting, contract administration, and risk management into the Partnership's corporate office. In addition, we will retrain personnel at the referenced subsidiary on our statement of Business Conduct, Whistleblower, and Conflicts of Interest policies.

Certain of the remediation measures described above are subject to our internal controls assessment, testing and evaluation processes which we are in the process of completing. We believe that these measures will remediate the identified material weakness and strengthen internal control over financial reporting. As we continue to evaluate and enhance our internal control over financial reporting, we may determine that additional measures need to be taken to address the material weakness or that we need to modify or otherwise adjust the remediation measures described above.

DISCLOSURE 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 our annual and quarterly reports under the Exchange Act within the time periods specified by the SEC's rules and forms and that such information is accumulated and communicated to our management, including our principal executive officer and principal financial officer, as appropriate, to allow timely decisions regarding required disclosure. Our management has evaluated, with the participation of our principal executive officer and principal financial officer, the effectiveness of our disclosure controls and procedures as of March 31, 2012. Based upon that evaluation and the identification of the material weakness in our internal controls over financial reporting as described above, our principal executive and principal financial officers concluded that our disclosure controls and procedures are not effective to accomplish their purpose. 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.

CHANGES IN INTERNAL CONTROLS OVER FINANCIAL REPORTING

The changes to our internal control over financial reporting described above under "Remediation" occurred during the three month period ended March 31, 2012. These changes have materially affected the Partnership's internal control over financial reporting as it relates to the referenced subsidiary.

PART II—OTHER INFORMATION

Item 1. Legal Proceedings

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

Item 1A. Risk Factors

There have been no material changes to risk factors as previously disclosed in our Annual Report on Form 10-K for the fiscal year ended December 31, 2011.

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, 2012

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

Date: May 1, 2012

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

Index of Exhibits

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

Exhibit Number	Description
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 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 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, 2012

By: /s/ Mark A. Maki

Mark A. Maki
President
(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 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 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, 2012

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

CERTIFICATE 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, 2012 (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, 2012

By: /s/ Mark A. Maki

Mark A. Maki
President
(Principal Executive Officer)
Enbridge Energy Management, L.L.C. (as delegate of the General Partner)

Exhibit 32.2

CERTIFICATE 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, 2012 (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, 2012

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)